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ESL-TR-85-27

Biomass Economy

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FINAL REPORT

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AFESC

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The objective of this effort was to perform an updated life cycle cost assessment of biomass energy conversion systems capable of meeting facility and process energy needs of Eglin AFB FL. System capacities examined in this study were 25-MW_e and 15-MW_e. Results of the study are that although the biomass fuel is available at a reasonable cost, construction and other operating costs are too high to justify implementation of this technology based on the current cost of electricity at Eglin AFB FL.

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PREFACE

This report was prepared by Ultrasystems, Inc., 16845 Von Karman Ave, Irvine CA 92714, under Contract Number F08635-84-C-0229, for the Air Force Engineering and Services Center, Engineering and Services Laboratory, Tyndall AFB FL.

This report summarizes work done between 1 June 1984 and 30 ~~May~~ NOV. 1985. The HQ AFESC/RDCS project officer for this effort was Captain Paul C. Vitucci. This work follows earlier less detailed biomass energy technical and economic analyses summarized in CEEDO-TR-78-41, FLAME: Forestry Lands Allocated for Managing Energy; ESL-TR-81-11, Advanced Bio-Energy Systems for Air Force Installations; ESL-TR-82-09, Biomass Energy Self Sufficiency Resource Alternatives for a Forested Air Force Installation; Solar Energy Research Institute TR-256-1477, Technical and Economic Review of Wood Energy Systems for Military Bases; and ESL-TR-83-04, Implementation of a Biomass Energy Island for a Forested Air Force Installation.

This report has been reviewed by the Public Affairs Office (PA) and is releasable to the National Technical Information Service (NTIS). At NTIS, it will be available to the general public, including foreign nationals.

This report has been reviewed and is approved for publication.

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SUMMARY

The research reported here was initiated to determine whether a biomass-fueled energy production facility could provide an economical, but more secure energy source for Eglin Air Force Base. The basic criteria for the report recognized that complete energy independence was neither desirable or economical. The scope of the report required that two different scenarios for plant size be considered and examined for financing and operation by either a private third-party or MILCON. The plant sizes were intended to provide for essential requirements of (1) the entire Eglin AFB complex and (2) the Main Base segment only.

A requirement of the work scope was the consideration of providing both thermal and electrical energy. The fact that thermal requirements for the base are presently provided by small decentralized natural gas-fueled boiler plants or direct-use natural gas appliances, together with the relatively short heating season made it immediately evident that it would not be economical to convert to a centralized system with underground distribution.

The plant sizes studied for the entire Eglin AFB complex and the Main Base were 25-MW and 15-MW output, respectively. These plants could supply roughly 80 percent and 76 percent of the annual electrical energy usage for the respective base segments and permit operation of all essential services under emergency conditions.

A financial pro forma for each of the plant sizes was run for both third-party and MILCON financing and operation. These pro formas in Section IV of the report, indicate that the return on investment required to attract a third-party operator would increase rather than decrease the electrical energy costs in either the 25-MW_e or the 15-MW_e case. These cost increases would vary from 12.8 and 8.8 percent in the first full year of operation, to 5.3 and 11 percent in the 15th year for the 25-MW_e and 15-MW_e cases, respectively. Should funding be available for the MILCON cases however, the cost of electrical energy would be reduced by roughly 7

percent for either plant in the first full year of operation and to 16 and 19 percent in the 15th year for the 25-MW_e and 15-MW_e cases.

In summary, except for reasons of national security, it is impossible to recommend implementation of either sized plant when it indicates a negative net present value and a maximum rate of return of 5.2 percent for the most favorable of the cases studied.

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GLOSSARY

AC	Alternating Current
AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
AWWA	American Water Works Association
BEI	Biomass Energy Island
Btu	British thermal units
CSP	Choctawatchee sand pine
dB	Decibels
dBA	Decibels A-Scale
DC	Direct Current
EPA	Eglin Procurement Area
ESP	Electrostatic Precipitator
FIRS	Forest Inventory Retrieval System
FLAME	Forestry Lands Allocated for Managing Energy
FD	Forced Draft
gsdf	grains per standard dry foot
HEI	Heat Exchange Institute
HgA	Mercury Absolute
hr	hour
HHV	Higher Heating Value
HVAC	Heating, Ventilation, Air Conditioning
ID	Induced Draft
kV	kilovolt
kVA	kilovolt-Ampere
kW	kilowatt
kWh	kilowatt-hour
lb/hr	pound per hour
M	Thousand
MC	Moisture Content
MM	Million
MW	Megawatt
MWe	Megawatt-electric
MWH	Megawatt Hours
$MWHx10^3$	Thousands of Megawatt Hours
NFPA	National Fire Protection Association
NPSH	Net Positive Suction Head
%	Percent
pH	Hydrogen Ion Concentration
psia	pounds per square inch absolute
PVC	Polyvinyl Chloride
TAC	TAC Substation
tph	Tons per hour
UBC	Uniform Building Code
UPC	Uniform Plumbing Code
USDA	United States Department of Agriculture
USFS	United States Forestry Service
WPCF	Water Pollution Control Federation
yr	year

SECTION I
INTRODUCTION

A. OBJECTIVE

The objective of this effort was to perform an updated assessment of the current and anticipated process and facility energy requirements at Eglin AFB, Florida, and, based on these results, to project installed equipment costs and operating costs for the biomass energy conversion systems proposed to meet these requirements. Results of this investigation will be combined with previous data from extensive technical efforts examining the feasibility of developing and implementing biomass energy conversion systems to provide facility and process energy for Eglin AFB.

B. BACKGROUND

"Energy Crises" of the past decade have highlighted the fact that the United States remains dependent upon uncertain suppliers of imported fossil-fuel. Energy security is important to the United States, but mandatory for the armed services, and especially critical for the Air Force, which depends on the security of its airbases for mission accomplishment. The Navy takes its ships and airplanes to the combat zone; while the Army deploys its forces to the theater of operations. The Air Force, on the other hand, conducts its operations largely from established bases, which must be secure and capable of uninterrupted operations.

An Air Force alternative to liquid fuel dependency for base operation would be a locally available energy source such as renewable biomass. Realizing the vulnerability of its installations to fossil-fuel interruptions, the Air Force began an in-house study in 1978 to evaluate the feasibility of using wood grown on Air Force installations to supply the heating energy requirements of those installations, thereby, replacing the conventional fossil-fuels in use. That study, Forestry Lands Allocated for Managing Energy (FLAME), identified Air Force installations with the potential for satisfying significant portions of their energy requirements with cull trees grown on the installation.

Three followup studies to the FLAME study were conducted. The first study addressed the technical issues of interfacing biomass conversion systems with in-place energy systems and found that Eglin Air Force Base had the highest technical and dollar payoff potential. The second study focused on Eglin Air Force Base as a model Biomass Energy Island (BEI) and addressed the issue of utilizing the installation's resources under a BEI concept. Based on the maximum wood fuel requirement of 540,000 green tons per year, that second study identified 90,000 net producing acres out of the 464,000 acres of Eglin AFB for inclusion in biomass energy plantations which would not interfere with the Base's mission. The second study also recommended a superior silvicultural option that included the Choctawhatchee sand pine (CSP) as the species to cultivate.

The third study described a program to implement the BEI concept, including: timber management methods, silvicultural practices, fuel harvesting and delivery, and base management requirements.

Because several years have passed since the Energy Conversion systems were originally described, one of the findings of the third study was that these systems were no longer in tune with updated energy consumption data and new management plans. Accordingly, the Air Force commissioned this study to reconsider Eglins' energy consumption profile, apply current thinking to the energy conversion systems described, and recommend the optimal system based upon current findings. Additionally, an economic analysis is to be provided for two situations. The first is for an Air Force-owned and operated system and the other is for third-party operation.

C. SCOPE

This study evaluated the economic feasibility of applying current wood-burning energy conversion technologies on Eglin AFB.

It consisted of four technical tasks:

- Revised assessment of current and projected process and facility energy requirements.

- A determination of recommended system capacities and corresponding detailed estimates of the cost-effectiveness of each.

- A summary briefing.

- A technical report.

The approach was to look at small power production systems in two capacities: (1) to provide 100 percent of the minimum monthly sustainable electrical requirements of the main base, and (2) to provide 100 percent of the minimum monthly sustainable electrical requirements of the entire Eglin AFB community.

Cost-effectiveness determination of each system will be shown for both third-party financing and military construction funding.

SECTION II
ENERGY REQUIREMENTS

A. INTRODUCTION

To establish a basis for overall recommendations for the size and types of equipment to be used in the BEI concept, data on the use of energy of all types on the base for a full-year were obtained.

B. BASE DEMANDS

1. Thermal

Thermal demands of major buildings on the base are presently met by small decentralized boiler plants operating on natural gas fuel. Smaller buildings and housing facilities are provided with direct-use, natural gas-fired appliances because the capital expenditures required to provide thermal energy to even the major buildings from a central location would be prohibitive. No further study of this option was initiated.

2. Electrical

Electrical power for Eglin AFB is provided by Gulf Power Company through two major substations. The larger Valparaiso Substation feeds directly the North Gate, Foster, and Main Base substations. Through a 25-kV switching station, it preferentially feeds the West Range, East Range, Florosa, Auxiliary 9, and Site A-20 substations. The smaller unit, West Gate Substation, feeds the family housing area and the TAC substation. In addition, the West Gate Substation can provide emergency power to the other Eglin satellite substations connected to the switching station by tying in to the 25-kV switching station.

Gulf Power Company furnished computer printouts of hourly demands for each of the major substations for the Calendar Year 1983. Extracting the data from these printouts, three annual demand profiles were created and labeled Figures 1, 2, and 3 showing absolute maximum demand, 5-day minimum demand all on a weekly basis. These figures represent the combined total base demand, Valparaiso Substation demand, and West Gate Substation demand, respectively.

C. PLANT SIZE SELECTION

In conformance with the statement of work for the contract, two sizes of plants have been identified. These sizes, nominal 25-MW_e (net) and 15-MW_e (net), were selected on the basis of the review of Figures 1, 2, and 3 referenced in the previous paragraph. An evaluation of the electrical profiles revealed that plants sized to meet the maximum demands of the two options would usually operate far below their design capacities, or would require significant export of power to the serving utility. The final selection was made on the basis of providing plants of sufficient size to meet the essential base loads throughout the year and to be able to follow base demands below the plant nominal rating without exceeding the turn-down characteristics of the biomass-fired boilers.

The 25-MW_e (net) plant was selected for the "entire Eglin community" option, and would be "base-loaded" for the greater portion of the year. It would electric-load follow only during the time when the total base demand fell below the 25-MW_e level. This option would require an internal base tie-line operating at 25-kV between the Valparaiso Substation and the West Gate Substation together with lock-out of the utility feed to the West Gate Substation. With this arrangement, the plant would be able to produce 79.3 percent of the total annual electrical consumption of the Eglin community on a full-availability basis.

The 15-MW_e (net) plant was selected for the Eglin "Main Base" option and would serve only those facilities presently connected through the Gulf Power Company Valparaiso Substation. The areas being served by the West Gate Substation would continue to be served by Gulf Power. In this case, the plant

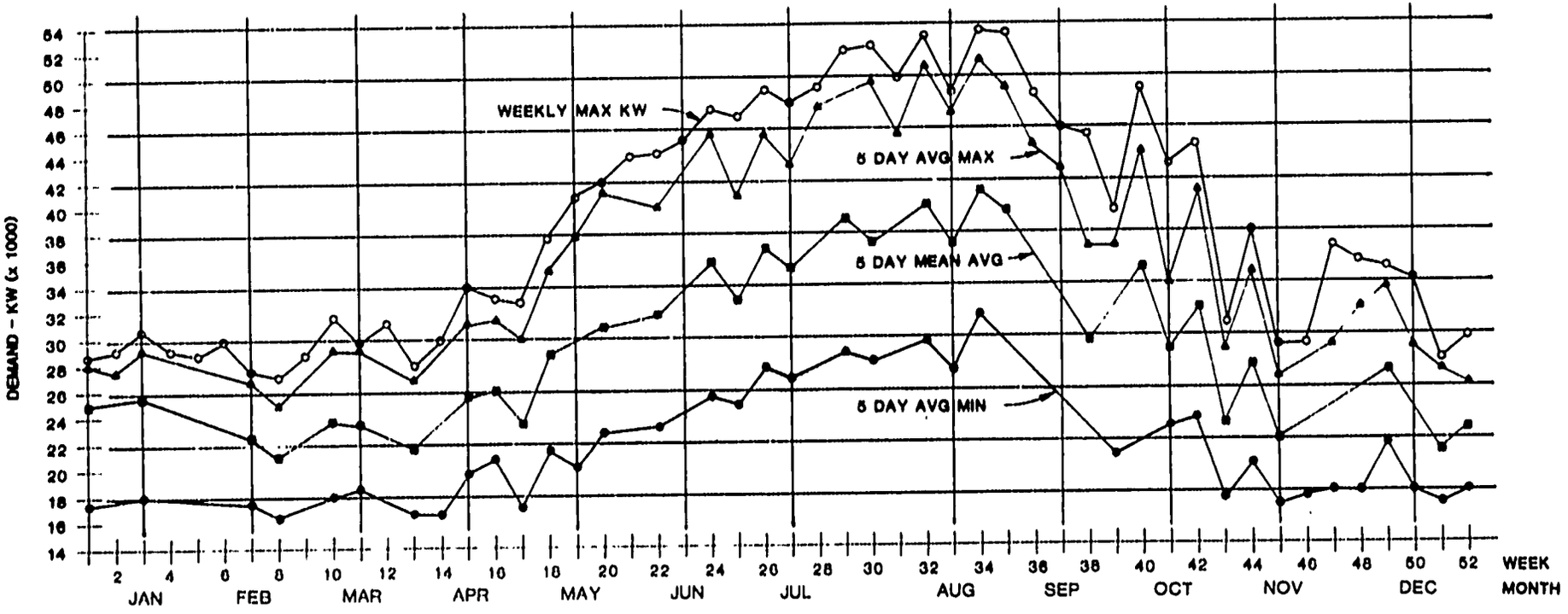

Figure 1. Load Curves - Total Base Consumption.

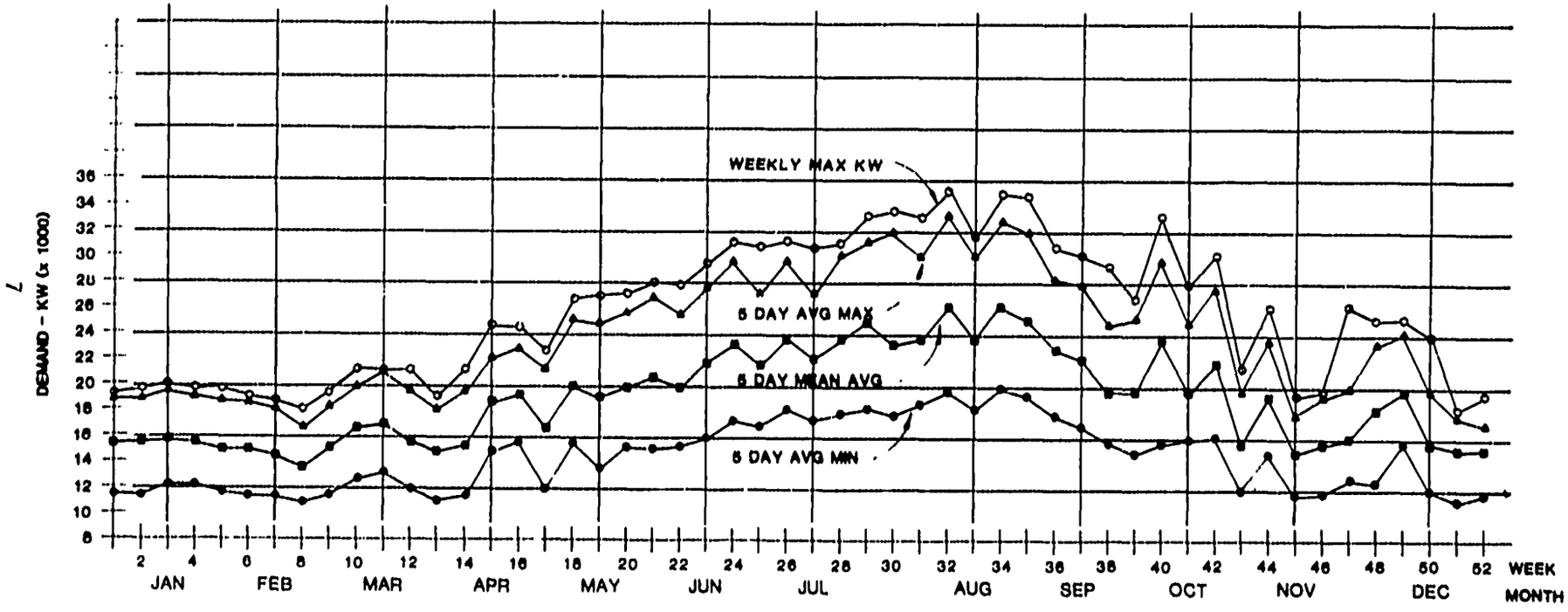

Figure 2. Load Curves - Valparaiso Substation.

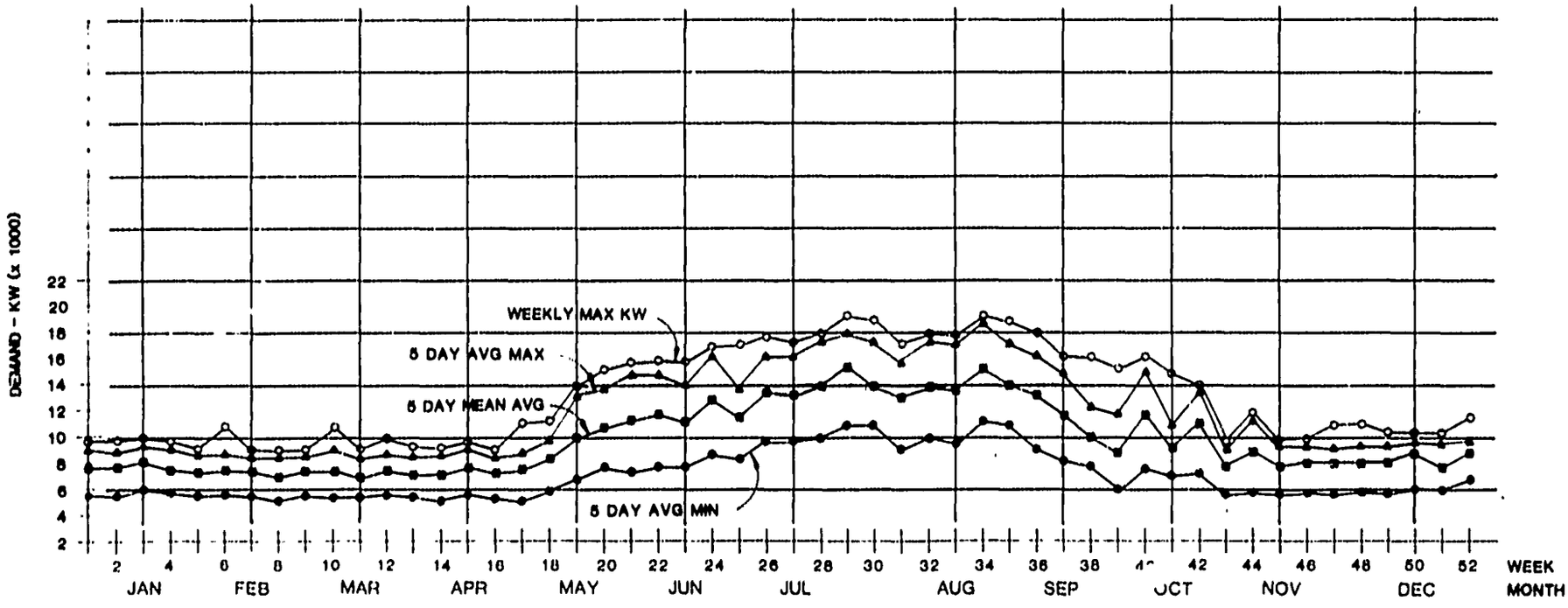

Figure 3. Load Curves - West Gate Substation.

would be able to produce 73 percent of the total annual electrical consumption of the Eglin Main Base facilities. Similar in operation to that of the large plant, the 15-MW_e facility would be base-loaded, except for those times when the requirements of the Main Base were below the 15-MW_e level. In neither case would there by any power export since the purchase price rates of Gulf Power Company are so low as to make export uneconomical.

The following tabular summary serves to illustrate the relationship of the plant sizing to the base demands.

Nominal Plant Output (MW_e)	Fuel Usage @ Rating w/47% MC (TPH)	Annual MWH @ 7,700 hr/yr Availability (MWHx10^3)	Total Base Usage/Year (MWHx10^3)	Main Base Usage/Year (MWHx10^3)	% Base Usage w/Plant at 7,700 hr/yr Availability (%)
25.0	41.4 (1)	192.5	242.1	--	79.5
15.0	24.9	115.5	--	158.1	73.1

(1) With Valpariso/West Gate Intertie

The availability of 7,700 hours per year allows for roughly 12-percent downtime for both routine and unscheduled maintenance that could be expected for plants of this type.

D. BIOMASS RESOURCE REQUIREMENTS

1. General

Past studies have demonstrated the potential for producing energy-wood on lands owned by Eglin AFB. These studies also indicated that the base could achieve energy self-sufficiency with wood grown on its own land. A later study by Batelle, Columbus recommended a management regime for the forested lands on Eglin which precluded this action. The present study explores the possibility of an alternative to onbase wood production; the procuring of wood from other forest land in the vicinity. It assesses the availability of energy-wood biomass within the Eglin Procurement Area (EPA).

This study must be considered as a gross estimate of the available wood volume and may serve as a basis for decision-making at this time. Its level of accuracy is consistent with the present status of the project. Estimates of available volume and production are deliberately conservative and are based on the following assumptions:

- 50-mile truck haul limit.
- No wood will be available from Eglin AFB land.
- No wood will be available from land-owned, or leased by forest industries. (It is probable that local forest industries will eventually use energy-wood from their holdings to fuel their own operations.)
- Estimates of "now-available" cut include only the volume which will come from hardwoods not suitable for sawlog production. They do not include logging slash from pine operations, pine saplings, or any volume from sparse pine stands or offsite pine plantations which might be harvested for energy-wood, nor do they include possible cuts from extensive area sand pine plantations which may be available for energy-wood harvest, if the price is right. No estimate is made of possible volumes available from mill residues or from urban waste (landfill).

The Eglin Procurement Area (EPA) is considered as roughly the land within a 50-mile radius of the base. Longer haul distances are common for energy-wood chip hauls in the area; however, we will use the 50-mile limit as a conservative and certainly economical truck haul distance for this area. No consideration has been given to rail-haul delivery, although this is a possibility. The 50-mile limit concept is operationalized through the use of a five-county study area, using the Forest Inventory Retrieval System (FIRS) of the USDA, Forest Service. Figure 4 is a map showing the five-county area which

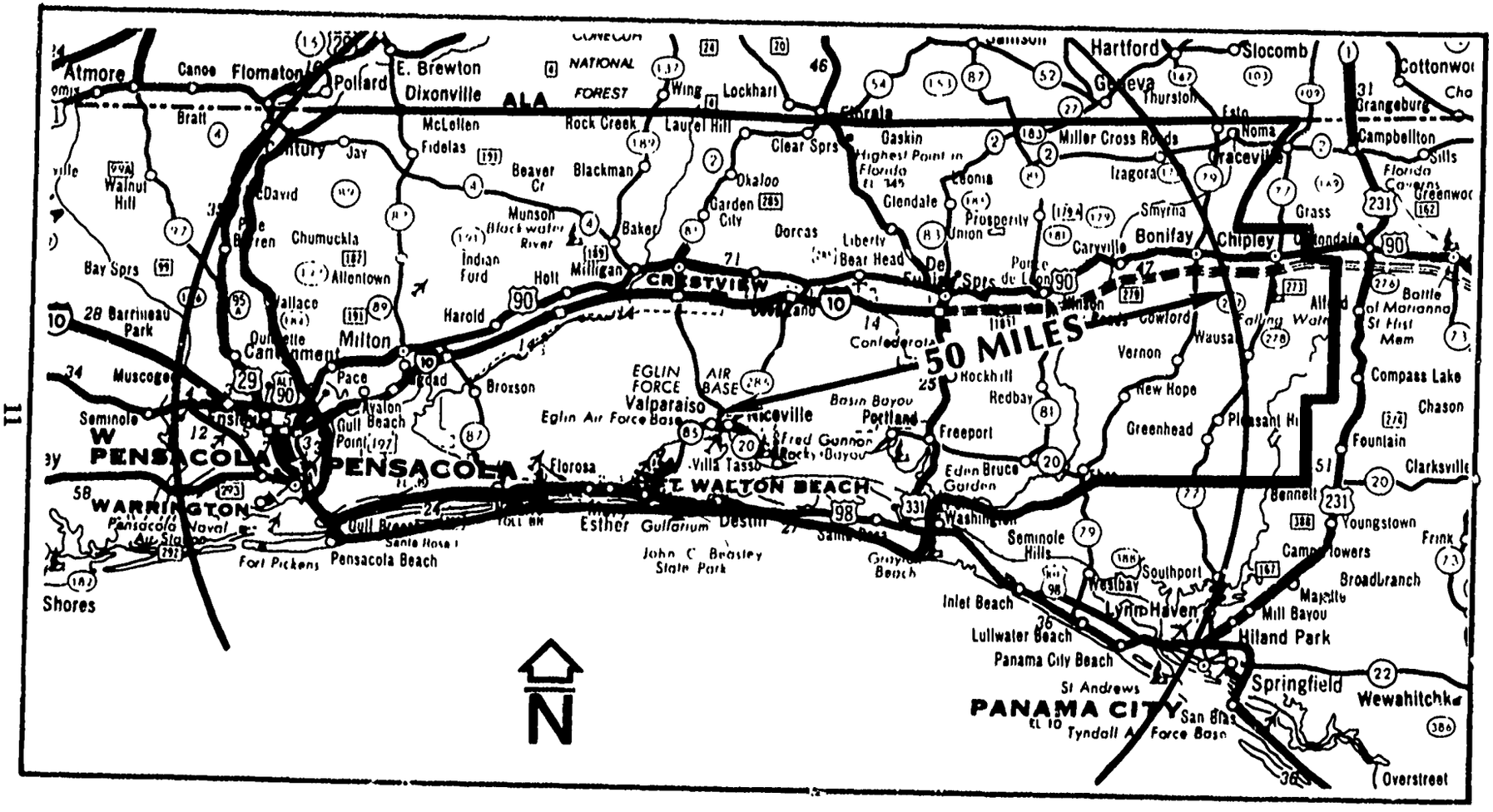

Figure 4. Map of Five-County Procurement Area.

roughly approximates the boundary of the procurement area. About 30 percent of the EPA lies within the state of Alabama. As the USFS was not able to furnish a printout combining Covington County, Alabama with the Florida data, the Florida data were expanded on a pro rata basis to adjust for this fact.

The report will consider for the EPA:

- Land available for energy-wood production.
- Existing energy-wood volumes.
- Harvestable energy-wood volumes and growth.
- Probable prices for delivered wood.

2. Land Available

Within the five-county Florida base area, the following is the distribution of commercial forest land:

	Acres
Public	590,000
Forest Industries	448,000
Leased, Forest Industries	72,000
Farmer	263,000
Miscellaneous Private	629,000
TOTAL	2,002,000

If Eglin lands (404,000 acres) and forest industry-controlled lands (520,000 acres) are excluded, a total of about 1,078,000 acres (54 percent of the total) is available in Florida as an energy-wood source. An estimated 550,000 acres of nonforest industry-owned land are available in Alabama, giving a total of about 1.6 million acres. This is the land base which can be drawn upon to supply Eglin's energy needs.

Of this available land, 40 percent is in pine-type, 19 percent in pine hardwood, and 41 percent in hardwood type. Importantly, more than 80 percent of the land is on uplands suitable for year-long logging.

3. Existing Energy-Wood Volumes

In this study, existing energy wood is defined as bole, tops, stumps and saplings of rough and rotten hardwood and pine, plus tops of growing stock trees. In addition, an arbitrary 25 percent of growing stock hardwoods of less than sawlog size trees have been assigned as candidates for energy-wood harvest. When calculated volumes from the five-county study area are adjusted for the exclusion of Eglin and Forest Industry lands, and the inclusion of Alabama lands, a total of 21 million tons of energy-wood exists within the Eglin Procurement Area.

4. Harvestable Volumes and Growth

Not all of the existing volume can be harvested. The USFS Forest Inventory Retrieval System quantifies those land areas within the survey area that need silvicultural treatment into broad management classes. FIRS also provides information on growing stock volumes found on such areas and other stand demographic data which can be manipulated to predict the volume of energy-wood probably harvestable from these lands. Calculated energy-wood yield volumes for harvestable private land within the five-county study area, by management classes, are shown in Table 1 below.

TABLE 1. HARVESTABLE ACRES AND YIELDS, PRIVATE LAND.

	OPERABLE ACRES (M) / TONS/ACRE YIELD			
	Nat. pine	Oak-pine	Upland H.	Lowl. H.
Salvage and Harvest	12 - 8	4 - 39	--	10 - 73
Conversion and Regen.	--	90 - 9	144 - 10	66 - 13
Total Acres (M) and MM Tons	12 /0.1	94 / 1.0	144 / 1.4	76 / 1.6

Total energy-wood yield for the 892,000 acres of nonindustrial private forest land in the 5-county area is 4.1 million tons or 4.6 tons/acre. Applying this value to the nonindustrial forested acreage (1.6 million) within the EPA results in an indicated harvestable volume of about 7 million tons.

Net annual growth for rough and rotten culls of all species is calculated to be 2.8 percent. Another 1.0 percent is removed annually for firewood, site preparation, etc. It appears that as much as 3.8 percent of existing energy-wood volume would be available annually on a "sustained yield" basis. This growth amounts to about 800,000 tons annually.

A conservative estimate is that 7 million tons of energy-wood are now harvestable within the EPA, and another 800,000 tons are being produced annually. Maximum requirements for the 25-MW_e plant are less than 400,000 tons per year.

5. Probable Prices for Delivered Wood

A well-established energy-wood harvesting and delivery system exists within the EPA. As many as 400,000 tons are harvested annually for energy-wood in the Florida Panhandle area, practically all of it from company-owned lands.

Delivered prices are negotiated and vary with haul distance, cut per acre, and current status of operator needs. Recent (1984) contract-delivered chip prices (adjusted to a 35-mile average haul, and $1.000 per ton stumpage) ranged from $10.95 to $15.50 per ton and averaged $13.83. A recent bid for 310,000 tons annually, solicited by the City of Tallahassee, produced a low bid of $13.90 per ton. This bid is now under negotiation and may require a resolicitation. As energy-wood markets develop in the area, an increase in prices can be expected, but under current market conditions, wood in large quantities can almost certainly be obtained at $15.00 or less per delivered ton for wood chips at less than 50-percent moisture content.

SECTION III
PROJECT DEFINITION

A. GENERAL

The following project definition is specific for the 25-MW_e net plant size, but since both plants have identical cycles and functions, it is applicable for the 15-MW_e net plant if all flow and use rate values are adjusted to 60 percent of the values specified for the 25-MW_e plant. This 60-percent flow factor can also be used to correct the fundamental flow diagram, while the plant layout and elevations will not differ significantly for the smaller plant. Complete computer performance printouts are included for both plants in Appendix A.

The project includes the conceptual design, construction, and startup of a wood fuel-fired power plant producing a nominal 25-MW_e of electrical power. Appendix B includes an area location plan, plant arrangement, elevations, fundamental flow diagram, and electrical single-line for such a plant. The facility will include provisions for receiving, handling and storage of wood fuel, the production of electrical power, and interconnection to the area electrical distribution system.

The project will be designed for continuous high availability, maximizing megawatt production. To provide this reliability, wherever practicable, backup equipment will be provided in the critical areas, such as feed pumps, condensate pumps, and circulating water pumps.

B. SUMMARY OF MAJOR EQUIPMENT

1. Wood-Handling Equipment

The wood-handling system will provide a means of receiving, classifying, storing, and reclaiming woodwaste to the boiler feed hopper. The wood-handling system consists of the following major items of equipment:

- Two Truck Dumpers with Scales
- Two Receiving Hoppers
- Magnet
- Disc Screen Classifier
- Wood and Bark Hog
- Open Storage Reclaim System
- Buffer Storage before the Boiler
- Stackout and Reclaim Conveyor Systems

2. Steam Generator

The steam generator will be a fluidized-bed type boiler. The boiler package includes the required startup heater, economizer, superheater, induced draft and forced draft fans, and emission control equipment. The boiler design parameters are:

Design Capacity	216,000 lb/hr
Design Outlet Pressure	1,265 psia
Design Outlet Temperature	955°F
Wood Fuel Firing Rate at 47-Percent Moisture Content	41.4 ton/hr

3. Air Quality Control Equipment

The facility will be equipped with an air quality control system to remove particulate from the boiler gases to meet the presently acceptable emission levels. The air quality control system will consist of a mechanical dust collector and an electrostatic precipitator, or baghouse.

4. Condenser System

The facility will be equipped with a multimodule, wet surface, air-cooled condenser, designed to operate at a design wet-bulb temperature of 77°F.

5. Turbine Generator

The turbine generator unit will consist of a single-casing, condensing turbine, and a closed-air/water-cooled generator operating at 3,600 rpm. The turbine design conditions are:

Throttle Steam:	
Pressure	1,250 psia
Temperature	950°F
Flows	216,000 lb/hr
Exhaust Steam:	
Pressure	2.5-inches HgA
Number of Extractions	2
Number of Feedwater Heaters	1 Deaerator
	1 Low-Pressure

6. Electrical Equipment

Electrical equipment will be provided to control and deliver power to the base grid, and to serve internal plant loads.

Major electrical equipment will include a 13.8-kV switchgear assembly with utility tie breaker, generator, and plant service fused disconnects.

7. Instrumentation and Control Equipment

A central control room will be provided for remote startup, monitoring, control, and shutdown of frequently operated equipment. Local controls will be provided. The operator interface will consist of a centralized, dedicated control system, auto/manual stations, indicators, recorders, and annunciators.

C. DETAILED DESIGN DESCRIPTION

The design description of the two different-sized plants is covered in Appendix C of the report. It includes not only a general description of the work items and equipment, but design criteria used and a description of the function of the various sytems involved.

SECTION IV

ECONOMICS

A. GENERAL

The scope of this study requested that we look at the economic feasibility of providing a supplemental electric power source to Eglin AFB through the construction and operation of a wood-fired power plant. The sizing of the plant was to be determined by the needs of the Main Base area and also of the total base. After review of electrical consumption records provided to us from January 1983 through July 1984, and the electrical rates structure that Eglin presently enjoys with Gulf Power, it was determined that the most economically efficient plant sizes to accommodate needs would be 15 MW_e for the Main Base and 25 MW_e for the total base. These sizes were determined so as to be able to base load the facility for maximum efficiency and also not trigger a higher rate structure for additional power needs.

B. PROJECT COST SUMMARY

1. Costing Criteria

Capital costs are associated with the active engineering design, procurement of equipment and materials, and the construction and startup of the plant.

The following assumptions pertain:

- The site is assumed to have good soil conditions of at least 3,000 pounds per square foot bearing capacity; no special foundation requirements have been allowed for.

- Present access roads are assumed adequate to serve this new generation plant, and only onsite roads have been costed, as required. All piping carrying services to and from the generation site is assumed to extend only to battery limits.

- Filtered water of city quality and adequate pressure to meet the stated requirement of the generation plant is assumed to be available at the generation site boundary. It is also assumed that all liquid effluent from the generation plant will be transferred to the base sewer system at the battery limits.

- No landscaping of the generation plant site is provided for. The perimeter of the generation plant site will be enclosed with chain link fencing, as shown in Appendix B (page 83).

- The generation plant will be of outdoor construction. A building will be provided to house the maintenance area, personnel facility, switchgear, and control room.

- The demineralization plant for the boiler feedwater is based on rented ion exchange units and does not include a regeneration plant.

- Water for fire protection is assumed available at the battery limit at adequate pressure to meet local codes and national standards.

- This project costing is based on union labor and constant December 1984 dollars.

No allowances have been made in the Capital Cost Estimates for the following items:

- Spare Parts
- Operation, Maintenance, and Test Equipment
- Office Furnishings

- Cranes
- Emergency Diesel Generator
- Emissions Monitoring Equipment
- CO Control
- Front-end Loaders

2. Capital Cost Estimates

The following pages present the construction cost estimates for the two different-sized facilities. The costs for the 25-MW_e plant are estimated to be approximately 39 million dollars, while those for the 15-MW_e plant are approximately 33 million dollars.

The economies of scale of the larger 25-MW_e plant are very apparent when the differences in capital costs are examined. With only an 18-percent increase in capital costs, a potential annual generating capacity of roughly 66 percent could be achieved. This would increase from 115.5 x 10^3-MWHr to 192.5 x 10^3-MWHr comparing the 15-MW_e plant to the 25-MW_e plant. In addition, while fuel usage and cost would be proportional to plant output, plant overhead costs such as operating labor and administration would be only marginally different.

TABLE 2. EGLIN AIR FORCE BASE, BIOMASS POWER PLANT, 25-MEGAWATT CASE.

CONSTRUCTION COST ESTIMATE

Item	Cost
Site Work	$ 477,500
Concrete	1,113,500
Structural Steel	424,800
Buildings	487,900
Equipment	17,053,000
Piping	1,642,000
Electrical	2,931,000
Instrumentation	778,000
Painting	163,000
Insulation	1,191,000
Miscellaneous Steel	343,000
Completion Items	353,000
Freight	501,000
Sales Tax	835,000
Engineering	1,620,000
Contractor's Overhead and Profit	5,750,000
Contingency	3,336,300
Total Cost	$39,000,000

TABLE 3. EGLIN AIR FORCE BASE, BIOMASS POWER PLANT
15-MEGAWATT CASE.

CONSTRUCTION COST ESTIMATE

Item	Cost
Site Work	$ 477,500
Concrete	1,033,600
Structural Steel	375,900
Buildings	450,000
Equipment	14,468,900
Piping	1,453,200
Electrical	1,905,900
Instrumentation	778,800
Painting	140,000
Insulation	1,053,900
Miscellaneous Steel	320,100
Completion Items	320,500
Freight	412,500
Sales Tax	687,600
Engineering	1,373,500
Contractor's Overhead and Profit	4,750,000
Contingency	2,998,100
Total Cost	$33,000,000

C. ESTIMATED COSTS TO COMPLETE

1. Third-Party Developer

To realistically analyze the costs associated with a turnkey contract to complete one of these plants as proposed, a Third-Party Developer must examine several other dynamic conditions, including cost of borrowed funds, equity required, preoperational expenses, spare parts inventory, fuel inventory, and working capital needed to bring the plant to where it can perpetuate its existence through production revenue generated.

Tables 4 and 5 summarize the flow of funds over the time required to bring each of these plants from concept to a working reality. In each example, a sources and uses of funds analysis demonstrates that the capital cost of the plant is expended through a construction schedule assumed to be 24 months' long. This timeframe is deemed adequate to allow the contractor to construct and start up the facility, which when accepted, would be turned over to the plant operator.

The following general assumptions were made in preparing each of the third-party owned sources and uses calculations:

- Construction begins July 1, 1985 and is complete June 31, 1987.
- Approximately 35 percent of the all-in cost of the development is provided by equity from the developer or a joint venture formed specifically to own the facility. Those funds are injected pro rata with loan funds during the 24 month construction period.
- The capital cost (EPC) is roughly equal to the construction cost estimates on the previous pages.
- The cost of borrowed funds is 13 percent per annum, plus standard loan funding charges, and legal expenses associated with the financing of similar projects.

- Wood-handling equipment, maintenance vehicles and a spare parts inventory are purchased during the last several months of the construction phase.

- An inventory of wood fuel is built up over a 6-month period prior to completion, allowing enough fuel for test firing of the facility during the startup phase.

- A working capital line is established to maintain the economic viability of the plant.

- Expenses of the developer and the plant operator are reimbursed or paid as they occur during the construction and startup phases. These costs also include interconnection facilities tying the proposed plant to Eglin's existing systems.

- The general contractor is subject to a 7.50-percent retention against work performed under the construction contract, until the job is complete.

TABLE 4. 24-MONTH INTEREST DURING CONSTRUCTION, EGLIN AIR FORCE BASE, 25-MEGAWATT CASE.

VARIABLES		MONTH	% CONSTR	EXPENDITURES	RETENTION 7.5%	NET EXPENDITURE	LOAN COMM FEE	OTHER COSTS	EQUITY CONTRIBUTION	MONTHLY CONSTRUCTION LOAN	INTEREST EXPENSE 13.00%	LOAN BALANCE
CAPITAL COST	1985	JUL	10.02%	4220	316	3903	6	468	0	0		
39000		AUG	1.73%	675	51	624	6	25	1700	430	29	2670
		SEP	1.73%	675	51	624	6	25	254	430	34	3107
DEBT FRACTION		OCT	2.13%	831	62	768	5	30	254	434	30	3542
70.00%		NOV	2.13%	831	62	768	5	100	312	530	44	4072
		DEC	2.14%	835	63	772	5	30	370	429	51	4699
LOAN ESTIMATE	1986	JAN	2.14%	835	63	772	5	50	313	545	57	5244
29679		FEB	4.13%	1611	121	1490	5	50	321	563	63	5807
		MAR	1.93%	753	56	696	5	75	600	1008	74	6015
COMM FEE RATE		APR	4.55%	1775	133	1641	5	75	301	549	80	7343
0.25%		MAY	4.55%	1775	133	1641	4	100	668	1133	92	8496
		JUN	6.18%	2410	181	2229	4	100	670	1160	105	9656
EQUITY ESTIMATE		JUL	8.32%	3245	243	3001	4	150	906	1532	121	11188
16700		AUG	10.62%	4142	311	3831	3	150	1225	2051	143	13240
		SEP	7.60%	2964	222	2742	3	175	1547	2581	171	15821
WORKING CAPITAL		OCT	6.90%	2691	202	2489	2	175	1134	1957	193	17778
1000		NOV	5.33%	2079	156	1923	2	175	1035	1824	212	19602
		DEC	4.85%	1892	142	1750	2	200	815	1497	229	21099
	1987	JAN	4.16%	1622	122	1501	1	200	750	1422	244	22521
		FEB	2.32%	905	68	837	1	235	661	1205	250	23807
		MAR	1.09%	737	55	682	1	250	417	914	268	24721
		APR	1.52%	593	44	548	1	300	342	838	277	25560
		MAY	1.33%	519	39	480	1	312	330	796	286	26356
		JUN	1.00%	390	29	361	0	400	1739	3025	318	29381
			100.00%	39000	2925	36075	83	3930	16700	29699	3306	29699

OTHER COSTS	
LEGAL	100
ORIG FEE	200
FEE OP	1500
EQUIP	1050
WORK INV	1000
	3930

USES		
EPC	39000	
LOC	3306	
COMM	83	
OTHER	3930	
W C	1000	
TOTAL	47319	

SOURCES		
L T DEBT	29619	64.76753
W C LOAN	1000	
EQUITY	16700	35.23251
TOTAL	47319	100%

EQUITY PHASING BY CALENDAR YEAR

1	2	3	TOTAL
2090	9344	4266	16700

TABLE 5. 24-MONTH INTEREST DURING CONSTRUCTION, EGLIN AIR FORCE BASE, 15-MEGAWATT CASE.

VARIABLES		MONTH	% COMPLETE	EXPENDITURES	RETENTION 7.50%	NET EXPENDITURES	LOAN COMM FEE	OTHER COSTS	EQUITY CONTRIBUTION	MONTHLY CONSTRUCTION LOAN	INTEREST EXPENSE 13.00%	LOAN BALANCE
CAPITAL COST	1985	JUL	10.82%	3571	268	3303	5	460	0	0		
33000		AUG	1.73%	571	43	529	5	25	1459	2317	25	2317
		SEP	1.73%	571	43	528	5	25	214	367	29	2684
DEBT FRACTION		OCT	2.13%	703	53	650	5	30	216	371	33	3056
70.00%		NOV	2.13%	703	53	650	5	100	265	453	38	3509
		DEC	2.14%	706	53	653	4	30	323	550	44	4059
LOAN ESTIMATE	1986	JAN	2.14%	706	53	653	4	50	244	466	49	4525
25615		FEB	4.13%	1363	102	1261	4	50	273	483	54	5008
		MAR	1.93%	637	48	589	4	75	500	841	64	5869
LOAN FEE RATE		APR	4.55%	1502	113	1389	4	75	258	474	69	6343
0.28%		MAY	4.55%	1502	113	1389	4	100	567	969	79	7312
		JUN	6.18%	2039	153	1886	4	100	577	995	90	8307
EQUITY ESTIMATE		JUL	8.32%	2746	206	2540	3	150	749	1311	104	9618
14300		AUG	10.42%	3365	263	3242	3	150	1041	1756	123	11375
		SEP	7.46%	2508	189	2319	3	175	1312	2206	147	13581
WORKING CAPITAL		OCT	6.90%	2277	171	2106	2	175	965	1679	165	15260
1000		NOV	5.33%	1759	132	1627	2	135	832	1346	182	16606
		DEC	4.85%	1601	120	1480	2	200	697	1289	196	18115
	1987	JAN	4.16%	1373	103	1270	1	200	650	1220	210	19343
		FEB	2.32%	766	57	708	1	235	569	1112	222	20456
		MAR	1.81%	624	47	577	1	250	365	801	230	21256
		APR	1.52%	502	38	464	1	300	320	730	230	21985
		MAY	1.33%	439	33	406	1	312	296	707	246	22692
		JUN	1.08%	339	25	313	0	400	1507	2630	275	25340
			100.00%	33000	2475	30525	72	3930	14300	25615	2913	25615

OTHER COSTS		USES		SOURCES		
LEGAL	100	EPC	33000	L T DEBT	25615	65.04921%
ORIG FEE	250	IDC	2913	M C LOAN	1000	
PRE OP	1500	COMM	72	EQUITY	14300	34.95080%
CONTIN	1050	OTHER	3930			
BEGIN INV	1080	W C	1000	TOTAL	40915	100%
	3930	TOTAL	40915			

EQUITY PHASING BY CALENDAR YEAR

1	2	3	TOTAL
2478	8116	3706	14300

2. Government as Developer

The preceding assumptions were applied to Table 6 and 7, summarizing the flow of funds over time for the construction of the same two facilities, except for financing, and costs associated with leveraging the plants. The result, of course is a lower all-in cost of building each proposed facility, assuming that a MILCON-funded project has no cost-of-funds or tax benefits to recognize.

TABLE 6. 24-MONTH INTEREST DURING CONSTRUCTION, EGLIN AIR FORCE BASE, 25-MEGAWATT CASE, MILCON-FUNDED PROJECT.

VARIABLES		MONTH	% COMPLETE	EXPENDITURES	RETENTION 7.5%	NET EXPENDITURE	LOAN 100%	OTHER 8.5%	EQUITY CONTRIBUTION	MONTHLY CONSTRUCTION LOAN	INTEREST EXPENSE 10.0%	LOAN BALANCE
CAPITAL COST	1985	JUL	10.00%	4226	316	3763	0	344	0	0		
39000		AUG	1.73%	675	51	624	0	57	4671	0	0	0
		SEP	1.73%	675	51	624	0	57	649	0	0	0
DEBT FRACTION		OCT	2.13%	831	62	769	0	70	649	0	0	0
70.00%		NOV	2.13%	831	62	768	0	70	793	0	0	0
		DEC	2.14%	835	63	772	0	71	948	0	0	0
LOAN ESTIMATE	1986	JAN	2.14%	835	63	772	0	70	942	0	0	0
0		FEB	4.13%	1611	121	1490	0	137	828	0	0	0
		MAR	1.93%	753	56	696	0	64	1146	0	0	0
COMP FEE RATE		APR	4.55%	1775	133	1641	0	151	771	0	0	0
0.25%		MAY	4.55%	1775	133	1641	0	151	1716	0	0	0
		JUN	6.15%	2410	181	2229	0	205	1741	0	0	0
EQUITY ESTIMATE		JUL	8.35%	3245	243	3002	0	276	2329	0	0	0
40630		AUG	10.67%	4162	311	3851	0	354	3331	0	0	0
		SEP	7.67%	2964	222	2742	0	253	3901	0	0	0
WORKING CAPITAL		OCT	6.53%	2691	202	2489	0	229	2917	0	0	0
0		NOV	5.73%	2079	156	1923	0	177	2644	0	0	0
		DEC	4.73%	1898	142	1756	0	161	2898	0	0	0
	1987	JAN	4.16%	1622	122	1501	0	138	1950	0	0	0
		FEB	2.38%	965	68	837	0	77	1361	0	0	0
		MAR	1.89%	737	55	682	0	63	1672	0	0	0
		APR	1.52%	593	44	548	0	50	932	0	0	0
		MAY	1.33%	519	39	480	0	44	840	0	0	0
		JUN	1.00%	390	29	361	0	33	4478	0	0	0
			100.00%	39000	2925	36075	0	3330	40630	0	0	0

OTHER COSTS		USES		SOURCES		
LEGAL	0	E&C	39000	L.T. DEBT	0	0.00%
MOBIL FEE	0	I.C.	0	M.C. LOAN	0	
PRE-OP	1.50%	CLAIM	0	EQUITY	40630	100.00%
CONTIN	1.25%	8 DT ICR	3430			
MISCELLANEOUS	1.00%	M.C.	0	TOTAL	40630	100%
	3430	TOTAL	42430			

EQUITY PHASING BY CALENDAR YEAR

1	2	3	TOTAL
7116	24234	10980	42630

TABLE 7. 24-MONTH INTEREST DURING CONSTRUCTION, EGLIN AIR FORCE BASE, 15-MEGAWATT CASE, MILCON-FUNDED PROJECT.

VARIABLES		MONTH	% COMPLETE	EXPENDITURES	RETENTION 7.50%	NET EXPENDITURE	LOAN CONN FEE	OTHER COSTS	EQUITY CONTRIBUTION	MONTHLY CONSTRUCTION LOAN	INTEREST EXPENSE 0.00%	LOAN BALANCE
CAPITAL COST	1985	JUL	10.00%	3571	268	3303	0	168	0	0		
35600		AUG	1.73%	571	43	529	0	25	3471	0	0	0
		SEP	1.73%	571	43	530	0	25	553	0	0	0
DEBT FRACTION		OCT	2.13%	703	53	650	0	30	553	0	0	0
		NOV	2.13%	703	53	650	0	100	600	0	0	0
		DEC	2.14%	706	53	653	0	30	830	0	0	0
LOAN ESTIMATE	1986	JAN	2.14%	706	53	653	0	50	683	0	0	0
0		FEB	4.13%	1363	102	1261	0	50	793	0	0	0
		MAR	1.93%	637	48	589	0	75	1311	0	0	0
CONN FEE RATE		APR	4.55%	1502	113	1389	0	75	664	0	0	0
0.00%		MAY	4.55%	1502	113	1389	0	100	1464	0	0	0
		JUN	6.18%	2039	153	1886	0	100	1489	0	0	0
EQUITY ESTIMATE		JUL	8.30%	2746	206	2540	0	150	1916	0	0	0
36630		AUG	10.62%	3505	263	3242	0	150	2699	0	0	0
		SEP	7.60%	2508	188	2320	0	175	3292	0	0	0
WORKING CAPITAL		OCT	6.90%	2277	171	2106	0	175	2495	0	0	0
0		NOV	5.33%	1759	132	1627	0	175	2281	0	0	0
		DEC	4.85%	1601	120	1480	0	200	1902	0	0	0
	1987	JAN	4.16%	1373	103	1270	0	200	1680	0	0	0
		FEB	2.30%	764	57	708	0	225	1470	0	0	0
		MAR	1.89%	624	47	577	0	250	948	0	0	0
		APR	1.52%	502	38	464	0	300	827	0	0	0
		MAY	1.33%	439	33	406	0	312	764	0	0	0
		JUN	1.00%	330	25	305	0	400	2098	0	0	0
			100.00%	33000	2475	30525	0	3630	36630	0	0	0

OTHER COSTS	
LEGAL	0
ORIG FEE	0
PRE OP	1500
EQUIP	1650
BEGIN INV	1000
	3630

USES	
EPC	33000
IDC	0
CONN	0
OTHER	3630
W.C.	0
TOTAL	36630

SOURCES		
L.T. DEBT	0	0.00%
W.C. LOAN	0	
EQUITY	36630	100.00%
TOTAL	36630	100%

EQUITY PHASING BY CALENDAR YEAR

1	2	3	TOTAL
6867	20960	9583	36630

3. Financial Forecasts

The financial forecasts which follow this section demonstrate by year the anticipated operating performance of each proposed plant under the "Third-Party-Developer" and "MILCON-as-Developer" scenarios. These estimates of the most probable operating results and corresponding distributions of benefits have been formulated, using assumptions described below which we believe to be significant in determining the reliability of the forecasting model. There is no assurance that the assumptions will prove to be completely accurate or that plant operations will not be affected by subsequent unanticipated events or circumstances.

Each set of third-party forecasts contains operating statements and balance sheets which give a detailed accounting of the relationships between the Tax and Book methods of tracking plant performance. MILCON-owned scenarios contain only book basis forecasts due to their tax-exempt nature. Unless otherwise noted below, an inflation factor of 6 percent pertains to all related costs of operation.

The following assumptions pertain:

a. Cost of Electricity

All electricity generated would be purchased by Eglin Air Force Base. The Energy Payments shown in the forecast were derived as a variable, which escalates over time, allowing the "Third-Party Developer" to recover costs, repay the debt incurred and yield approximately 30 percent on the original equity investment after 15 years of operation. This is a common requirement in the industry based on the risks associated with development and construction of facilities such as those proposed.

b. Cost of Fuel

Each facility is assumed to be capable of operating at an average of 88 percent of its rated design capacity, roughly the equivalent of 7,700 hours per year. Assuming an average moisture content of the available

fuel to be 47 percent, the annual fuel consumption for the plants would be roughly 319,000 tons and 191,000 tons for the 25-MW_e and 15-MW_e plants, respectively. Using the wood fuel costs of $15.00 per ton in 1984 dollars, escalated at 6 percent per annum, the annual usage for each plant would be $5.7 million and $3.4 million respectively, in 1987.

c. Operating Labor

The basis for properly manning these proposed biomass-fueled power plants was developed by consulting with companies which operate similar facilities.

The composition of the labor force as proposed is as follows:

Position	15-MW_e Plant	25-MW_e Plant
Plant Manager	1	1
Production Supervisor	1	1
Plant Engineer	1	1
Plant Operators	8	10
Wood-yard Operators	4	6
Maintenance Mechanics	3	4
Plant Clerk	1	1
Total Required	19	24

Average annual salaries, including benefits, overtime, and an operating management fee have been included in these cost estimates.

d. Repairs and Maintenance Costs

The normal manner of determining maintenance costs for facilities such as are considered in the report, is on the basis of the number of kilowatt hours produced. This method covers the costs of materials and labor required to keep the plant in service, including routine and unscheduled maintenance and required periodic overhauls of the plant equipment. The cost

used herein is four mils per kilowatt hour, at the 25-MW_e plant, and 4.6 mils at the 15-MW_e plant, based on experience at similar facilities. Using these values, the annual maintenance cost for the 25-MW_e plant producing 193 megawatt hours would be $773,000 per year, and in the case of 15-MW_e plant producing 116 megawatt hours per year, the maintenance costs would be $530,000 per year. Both of these figures are based on 1985 dollars and escalate at the rate of 6 percent per year.

e. Insurance

Each of the proposed operations will be subject to hazards, some of which may result in personal injury or property damage. The forecasts provide for "all-risk" insurance on each facility, employer's liability insurance, comprehensive general liability insurance, flood and earthquake insurance, boiler and turbine generator breakdown insurance, and business interruption insurance. Annual premiums for this coverage are estimated to be $200,000 for each plant, escalated from 1985 dollars.

f. Working Capital

It is assumed that each plant will require working capital to handle variations in wood inventories, unscheduled maintenance outages and the collection of receivables. The financial forecasts for the Third-Party Developer assume that a $1 million line of credit will be available during the final stages of construction, and gradually diminish in usage over the first 7 years of plant operation. The cost of these funds has been estimated 13 percent per annum.

The number of production days receivable outstanding from the sale of electric power is estimated to be 30 days.

Accounts Payable are estimated to be approximately 1 month's cost associated with the following:

Fuel Supply
Utilities & Ash Disposal
Repairs & Maintenance

Operations & Maintenance Labor

Fluid Bed Material
Insurance
General & Administration Expenses

g. Inventory

Wood fuel inventory assumed to be on hand once commercial operations are underway is estimated to be equivalent of approximately a 70-day supply.

h. Significant Tax Assumptions

The Third-Party Developer scenarios which follow include the latest federal and state income tax benefits as they relate to Qualified Progress Expenditures, Investment and Energy Tax Credits which are assumed to remain available as currently allowed by generally accepted accounting standards. No provision has been made within those forecasts to account for potential changes to existing federal tax rules. The percentage of the facility that is actually completed during a taxable year must be determined on the basis of actual experience in the construction of the facility, and such experience may vary materially from the estimates upon which the forecasts are based. The MILCON-funded scenarios, of course, carry no tax burden or debt assumptions.

i. Financing

On the Third-Party Developer forecasts, debt of approximately 65 percent of all-in costs was assumed, which is repaid over a 15-year period beginning 5 months after completion of the facility. This schedule of repayment is considered to be relatively aggressive under normal circumstances, but considering the strength of the proposed electric power purchaser, these most favorable terms should be available to the developer.

FORECASTED OPERATING RESULTS

OF A

25-MEGAWATT

THIRD-PARTY-OWNED FACILITY

TABLE 8. PROJECTED STATEMENT OF OPERATIONS - TAX BASIS. THIRD-PARTY DEVELOPER, 25-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
REVENUES																	
ENERGY PAYMENT	0	0	$4,574	$13,251	$16,134	$17,184	$18,244	$19,295	$20,336	$21,773	$22,554	$23,884	$25,354	$26,786	$28,187	$29,898	$30,127
TOTAL REVENUES	0	0	4,574	13,251	16,134	17,184	18,244	19,295	20,336	21,773	22,554	23,884	25,354	26,786	28,187	29,898	30,127
OPERATING EXPENSES																	
BID COSTING COST	15	103	107	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WOOD FUEL SUPPLY	0	0	2,859	6,241	6,403	6,788	7,195	7,627	8,084	8,569	[illegible]	9,628	10,206	10,819	11,468	12,156	12,885
FLUID BED MATERIAL	0	0	33	73	74	79	83	88	94	99	105	112	[illegible]	[illegible]	[illegible]	[illegible]	149
UTILITIES AND ASH DISPOSAL	0	0	98	134	197	208	221	234	248	263	279	296	313	332	352	373	396
OPERATIONS & MAINTENANCE LABOR	0	0	714	1,514	1,604	1,721	1,803	1,911	2,026	2,147	2,276	2,413	2,557	2,711	2,873	3,046	3,229
REPAIRS AND MAINTENANCE	0	0	455	921	977	1,035	1,097	1,163	1,233	1,307	1,385	1,468	1,557	1,650	1,749	1,854	1,965
DEPRECIATION REAL PROPERTY	0	0	72	132	123	108	96	84	72	63	63	63	58	63	68	68	68
DEPRECIATION PERSONAL PROPERTY	0	0	5,530	8,066	7,700	7,700	7,700	0	0	0	0	0	0	0	0	0	0
GENERAL AND ADMINISTRATIVE	0	0	53	127	142	161	182	173	159	153	162	172	182	193	205	217	230
INSURANCE	0	0	134	225	238	252	268	284	301	319	338	358	380	402	427	452	479
AMORTIZATION																	
PRESERVATION COSTS	0	0	128	255	255	255	255	128	0	0	0	0	0	0	0	0	0
LOAN FEES	0	0	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20
DEFERRED INTEREST	0	0	17	35	35	35	35	35	35	35	35	35	17	0	0	0	0
TOTAL OPERATING EXPENSES	15	103	10,111	17,592	17,765	18,342	18,954	11,744	12,272	12,973	13,744	14,562	15,411	16,313	17,287	18,319	19,423
INCOME (LOSS) FROM OPERATIONS	-15	-103	-5,537	-4,340	-1,629	-1,158	-710	7,551	8,064	8,801	8,812	9,322	9,943	10,474	10,900	11,579	10,713
INTEREST EXPENSE																	
TAX LOAN	0	0	1,730	3,329	3,723	3,551	3,324	3,372	3,138	2,744	2,712	2,426	2,096	1,715	1,283	791	264
WORKING CAPITAL	0	0	78	149	154	116	96	73	47	18	0	0	0	0	0	0	0
DURING CONSTRUCTION	356	1,456	1,493	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTEREST EXPENSE	356	1,456	3,301	3,477	3,877	3,668	3,420	3,445	3,185	2,763	2,712	2,426	2,096	1,715	1,283	791	264
INCOME (LOSS)	-371	-1,559	-7,838	-7,817	-5,506	-4,826	-4,130	4,106	4,879	6,038	6,100	6,896	7,847	8,759	9,617	10,788	10,449
DECREASE (INCREASE) IN ACCOUNTS RECEIVABLE	0	0	-1,373	-254	-56	-102	-103	-102	-101	-100	-76	-129	-143	-139	-134	-144	-22
DECREASE (INCREASE) IN ACCOUNTS PAYABLE	0	0	344	37	28	21	22	23	24	25	25	27	30	34	38	72	74
TAXABLE INCOME (LOSS)	$-371	$-1,559	$-7,867	$-8,034	$-5,534	$-4,907	$-4,211	$4,027	$4,802	$5,963	$6,049	$6,794	$7,734	$8,654	$9,521	$10,716	$10,501

TABLE 9. PROJECTED STATEMENT OF CASH FLOW. THIRD-PARTY DEVELOPER, 25-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
TAXABLE INCOME/(LOSS)	$-221	$-1,529	$-7,723	$-6,487	$-5,563	$-4,987	$-4,396	$4,047	$4,955	$5,747	$6,078	$6,924	$7,765	$8,683	$9,549	$13,614	$19,553
DEPRECIATION	0	0	5,572	8,199	7,820	7,808	7,796	84	72	60	60	60	60	60	60	60	60
AMORTIZATION	0	0	155	310	310	310	310	182	55	55	55	55	37	29	29	29	29
CONST PERIOD INT EXP	221	1,529	1,597	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCREASE IN INVENTORY	0	0	-121	-72	-76	-81	-86	-91	-96	-102	-108	-115	-122	-129	-137	-145	-154
CASH FLOW FROM OPERATIONS	0	0	-517	1,950	2,490	3,050	3,635	4,222	4,985	5,759	6,084	6,824	7,740	8,634	9,492	13,529	19,430
PRINCIPAL REPAYMENT TERM LOAN	0	0	0	-488	-684	-879	-1,075	-1,273	-1,563	-1,856	-2,051	-2,349	-2,735	-3,126	-3,517	-4,854	-4,857
PRINCIPAL REPAYMENT WORKING CAP	0	0	0	-113	-128	-146	-166	-189	-215	-244	0	0	0	0	0	0	0
CASH GENERATED DURING PERIOD	0	0	-517	1,349	1,678	2,025	2,389	2,764	3,287	3,659	4,033	4,480	5,005	5,508	5,975	8,675	14,573
BEGINNING CASH BALANCE	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200
WORKING CAPITAL BORROWING	0	0	1,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH BALANCE BEFORE DISTRIBUTION	0	0	683	1,549	1,878	2,225	2,589	2,964	3,487	3,859	4,233	4,680	5,205	5,708	6,175	8,775	14,573
CASH DISTRIBUTIONS TO:																	
3rd-PARTY	0	0	-241	-675	-839	-1,013	-1,194	-1,382	-1,684	-1,829	-2,017	-2,248	-2,563	-2,754	-2,988	-3,287	-3,186
CORPORATE PARTNER	0	0	-241	-675	-839	-1,013	-1,194	-1,382	-1,684	-1,829	-2,017	-2,248	-2,563	-2,754	-2,988	-3,287	-3,186
TOTAL CASH DISTRIBUTIONS	0	0	-483	-1,349	-1,678	-2,025	-2,389	-2,764	-3,287	-3,659	-4,033	-4,480	-5,005	-5,508	-5,975	-6,575	-6,373
ENDING CASH BALANCE	0	0	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
DEBT COVERAGE RATIO	0.00	0.00	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.94	2.04	2.14	2.24	2.36	2.47

TABLE 10. PROJECTED TAXABLE INCOME (LOSS), DISTRIBUTIONS OF AVAILABLE CASE AND ALLOCATIONS OF INCOME TAX BENEFITS (REQUIREMENTS) TO EQUITY PARTNERS. THIRD-PARTY DEVELOPER, 25-MEGAWATT CASE.

(In Thousands)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
TAXABLE INCOME(LOSS)	$-221	$-1,325	$-7,725	$-6,487	$-5,533	$-4,987	$-4,395	$4,047	$4,925	$5,747	$6,672	$6,824	$7,765	$8,680	$9,549	$10,694	$10,559
FED DEPRECIATION	0	0	5,572	8,199	7,820	7,886	7,796	84	72	60	60	60	60	60	60	60	60
STATE DEPRECIATION	0	0	-715	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430	-1,430
STATE TAXABLE INCOME(LOSS)	-221	-1,329	-2,869	282	826	1,391	1,976	2,701	3,597	4,377	4,708	5,454	6,395	7,314	8,179	9,324	9,189
STATE TAX BENEFITS (REQMTS)	28	137	256	-25	-74	-124	-176	-241	-321	-391	-420	-487	-571	-653	-730	-833	-816
FEDERAL TAXABLE INCOME (LOSS)	-281	-1,392	-7,464	-6,512	-5,637	-5,111	-4,566	3,806	4,634	5,356	5,657	6,337	7,194	8,038	8,818	9,861	9,688
NET AFTER TAX BENEFITS																	
FED TAX BENEFITS (REQMTS)	$99	$442	$3,434	$2,995	$2,595	$2,351	$2,101	$-1,751	$-2,131	$-2,464	$-2,602	$-2,915	$-3,309	$-3,694	$-4,057	$-4,536	$-4,456
STATE TAX BENEFITS (REQMTS)	28	137	256	-25	-74	-124	-176	-241	-321	-391	-420	-487	-571	-653	-730	-833	-816
CASH DISTRIBUTION (REQMTS)	0	0	483	1,349	1,676	2,025	2,389	2,764	3,267	3,459	4,036	4,486	5,045	5,588	5,975	6,575	6,373
INVESTMENT TAX CREDITS	748	2,411	730	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAX CREDITS	462	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	$1,338	$3,138	$4,902	$4,319	$4,197	$4,252	$4,313	$772	$755	$864	$1,013	$1,078	$1,125	$1,161	$1,188	$1,206	$1,101
DISTRIBUTION																	
EQUITY PARTNERS SHARE	$1,338	$3,138	$4,902	$4,319	$4,197	$4,252	$4,313	$772	$755	$864	$1,013	$1,078	$1,125	$1,161	$1,188	$1,206	$1,101
3-RD PTY CARRIED INTEREST	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	$1,338	$3,138	$4,902	$4,319	$4,197	$4,252	$4,313	$772	$755	$864	$1,013	$1,078	$1,125	$1,161	$1,188	$1,206	$1,101
EQUITY INVESTMENT	$-2,890	$-9,344	$-4,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET AFTER TAX BENEFITS	1,338	3,138	4,902	4,319	4,197	4,252	4,313	772	755	864	1,013	1,078	1,125	1,161	1,188	1,206	1,101
NET CASH FLOW	$-1,552	$-6,206	$636	$4,319	$4,197	$4,252	$4,313	$772	$755	$864	$1,013	$1,078	$1,125	$1,161	$1,188	$1,206	$1,101
EQUITY PARTNERS																	
INTERNAL RATE OF RETURN	0.00%	0.00%	0.00%	0.00%	5.83%	18.97%	26.24%	27.11%	27.74%	28.23%	28.75%	29.04%	29.35%	29.57%	29.74%	29.87%	29.9%
NET PRESENT VALUE AT 12% DISCOUNT RATE	-1,552	-7,227	-6,729	-3,645	-678	1,435	3,429	3,949	4,274	4,544	4,889	5,199	5,488	5,754	5,997	6,217	6,397

TABLE 11. PROJECTED STATEMENT OF OPERATIONS - GAAP BASIS. THIRD-PARTY DEVELOPER, 25-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
REVENUES																	
ENERGY PAYMENT	0	0	$6,574	$15,251	$16,136	$17,184	$18,244	$19,295	$20,336	$21,773	$22,554	$23,884	$25,354	$26,786	$28,187	$29,898	$30,127
TOTAL REVENUES	0	0	6,574	15,251	16,136	17,184	18,244	19,295	20,336	21,773	22,554	23,884	25,354	26,786	28,187	29,898	30,127
OPERATING EXPENSES																	
WOOD FUEL SUPPLY	0	0	2,300	6,041	6,403	6,788	7,195	7,627	8,084	8,569	9,083	9,628	10,206	10,819	11,468	12,156	12,885
FLUID BED MATERIAL	0	0	33	70	74	79	83	88	94	99	105	112	118	125	133	141	149
UTILITIES AND ASH DISPOSAL	0	0	88	184	197	208	221	234	248	263	279	296	--	332	352	373	396
OPERATIONS & MAINTENANCE LABOR	0	0	714	1,514	1,604	1,701	1,803	1,911	2,026	2,147	2,276	2,413	2,	2,711	2,873	3,046	3,229
REPAIRS AND MAINTENANCE	0	0	435	921	977	1,035	1,097	1,163	1,233	1,307	1,385	1,468	1,557	1,650	1,749	1,854	1,965
DEPRECIATION	0	0	422	1,243	1,243	1,243	1,243	1,243	1,243	1,243	1,243	1,243	1,243	1,243	1,243	1,243	1,243
GENERAL AND ADMINISTRATIVE	0	0	53	127	142	161	182	173	159	153	162	172	182	193	205	217	230
INSURANCE	0	0	104	225	238	252	268	284	301	319	338	358	380	402	427	452	479
AMORTIZATION																	
PRE OPERATION COSTS	0	0	25	50	50	50	50	50	50	50	50	50	50	50	50	50	50
LOAN FEES	0	0	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20
TOTAL OPERATING EXPENSES	0	0	4,934	10,397	10,949	11,538	12,162	12,791	13,458	14,171	14,943	15,769	16,627	17,546	18,529	19,552	20,647
INCOME (LOSS) BEFORE INT EXP	0	0	1,640	4,854	5,187	5,646	6,082	6,504	7,078	7,602	7,613	8,123	8,727	9,240	9,667	10,346	9,480
INTEREST EXPENSE																	
INTEREST EXPENSE																	
TERM LOAN	0	0	1,930	3,829	3,753	3,651	3,524	3,372	3,188	2,966	2,712	2,426	2,096	1,715	1,283	791	264
WORKING CAPITAL	0	0	78	149	134	116	96	73	47	18	0	0	0	0	0	0	0
TOTAL INTEREST EXPENSE	0	0	2,008	3,979	3,887	3,768	3,620	3,445	3,235	2,983	2,712	2,42.	2,096	1,715	1,283	791	264
PRETAX INCOME(LOSS)	0	0	$-369	$876	$1,300	$1,878	$2,462	$3,059	$3,843	$4,619	$4,902	$5,698	$6,631	$7,526	$8,384	$9,555	$9,216
ALTAMONT	0	0	$-184	$438	$650	$939	$1,231	$1,529	$1,921	$2,310	$2,451	$2,849	$3,316	$3,763	$4,192	$4,778	$4,608
CORPORATE PARTNER	0	0	-184	438	650	939	1,231	1,529	1,921	2,310	2,451	2,849	3,316	3,763	4,192	4,778	4,608
PRETAX INCOME(LOSS)	0	0	$-369	$876	$1,300	$1,878	$2,462	$3,059	$3,843	$4,619	$4,902	$5,698	$6,631	$7,526	$8,384	$9,555	$9,216

TABLE 12. PROJECTED BALANCE SHEETS. THIRD-PARTY DEVELOPER, 25-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CASH	0	0	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
ACCOUNTS RECEIVABLE	0	0	1,278	1,483	1,569	1,671	1,774	1,876	1,997	2,117	2,193	2,322	2,465	2,604	2,740	2,997	2,929
INVENTORY	0	400	1,201	1,273	1,350	1,430	1,516	1,607	1,704	1,806	1,914	2,029	2,151	2,280	2,417	2,562	2,715
TOTAL CURRENT ASSETS	0	400	2,679	2,956	3,118	3,301	3,490	3,683	3,900	4,123	4,307	4,551	4,816	5,084	5,357	5,669	5,844
PLANT AND EQUIPMENT	6,815	33,263	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519	43,519
ACCUMULATED DEPRECIATION	0	0	-622	-1,865	-3,109	-4,352	-5,595	-6,839	-8,082	-9,325	-10,569	-11,812	-13,056	-14,299	-15,543	-16,786	-18,029
NET OF PLANT & EQUIPMENT	6,815	33,263	42,897	41,654	40,411	39,167	37,924	36,680	35,437	34,194	32,950	31,707	30,463	29,220	27,977	26,733	25,490
UNAMORTIZED PREOPERATION COST	1,500	1,500	1,475	1,425	1,375	1,325	1,275	1,225	1,175	1,125	1,075	1,025	975	925	875	825	775
UNAMORTIZED LOAN FEES	300	300	290	270	250	230	210	190	170	150	130	110	90	70	50	30	10
TOTAL ASSETS	$8,615	$35,463	$47,342	$46,305	$45,154	$44,023	$42,899	$41,778	$40,682	$39,591	$38,462	$37,393	$36,344	$35,299	$34,259	$33,257	$32,119
ACCOUNTS PAYABLE	0	0	$594	$631	$669	$710	$754	$797	$843	$893	$946	$1,003	$1,063	$1,127	$1,194	$1,266	$1,342
WORKING CAPITAL LOAN	0	0	1,200	1,367	517	814	648	459	244	0	0	0	0	0	0	0	0
TERM LOAN-CURRENT	0	0	0	404	879	1,075	1,278	1,563	1,856	2,051	2,344	2,735	3,126	3,517	4,354	4 057	0
TOTAL CURRENT LIABILITIES	0	0	1,794	2,402	2,508	2,599	2,672	2,919	2,944	2,944	3,490	3,738	4,189	4,644	5,248	5,323	1,342
TERM LOAN-NONCURRENT	5,725	23,031	29,699	25,527	27,648	26,573	25,303	23,740	21,884	19,933	17,489	14,754	11,628	8,111	4,057	0	0
THIRD-PARTY DEVELOPER	1,445	6,217	7,924	7,688	7,499	7,426	7,462	7,619	7,927	8,407	8,942	9,451	10,264	11,272	12,477	13,967	15,389
CORPORATE PARTNER EQUITY	1,445	6,217	7,924	7,688	7,499	7,426	7,462	7,619	7,927	8,407	8,942	9,451	10,264	11,272	12,477	13,967	15,389
TOTAL EQUITY	2,890	12,434	15,849	15,375	14,998	14,851	14,924	15,239	15,855	16,815	17,883	18,901	20,527	22,544	24,953	27,934	30,777
TOTAL LIABILITIES AND EQUITY	$8,615	$35,463	$47,342	$46,305	$45,154	$44,023	$42,899	$41,778	$40,682	$39,591	$38,462	$37,393	$36,344	$35,299	$34,259	$33,257	$32,119

TABLE 13. UTILITY AVOIDED COST SCHEDULE. THIRD-PARTY DEVELOPER, 25-MEGAWATT CASE.

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
UTILITY AVOIDED COST	6 89	7 99	8.45	9 00	9.55	10.10	10.75	11.40	12 81	12 51	13 28	14.03	14.76	15.66	15.78

NOTE: COST OF ENERGY TO EGLIN AFB TO MAKE "THIRD-PARTY OPERATION FEASIBLE FOR A 25 MW_e PLANT.

TABLE 14. PROJECTED STATEMENT OF OPERATIONS - TAX BASIS. THIRD-PARTY DEVELOPER, 15-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
REVENUES																	
ENERGY PAYMENT	0	0	$4,079	$11,561	$12,654	$12,965	$13,659	$14,436	$15,371	$16,295	$16,778	$17,768	$18,865	$19,920	$20,937	$22,218	$22,196
TOTAL REVENUES	0	0	4,079	11,561	12,654	12,965	13,659	14,436	15,371	16,295	16,778	17,768	18,865	19,920	20,937	22,218	22,196
OPERATING EXPENSES																	
EQP DURING CONST	15	103	107	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WOOD FUEL SUPPLY	0	0	1,721	3,428	3,946	4,377	4,382	4,581	4,855	5,147	5,456	5,783	6,130	6,498	6,887	7,301	7,739
FLUID BED MATERIAL	0	0	33	70	74	79	83	88	94	99	105	112	118	125	133	141	149
UTILITIES AND ASH DISPOSAL	0	0	98	185	197	208	221	234	248	263	279	296	313	332	352	373	396
OPERATIONS & MAINTENANCE LABOR	0	0	576	1,220	1,293	1,371	1,453	1,540	1,633	1,731	1,835	1,945	2,061	2,185	2,316	2,455	2,602
REPAIRS AND MAINTENANCE	0	0	298	631	667	709	751	796	844	895	948	1,005	1,066	1,129	1,197	1,269	1,345
DEPRECIATION REAL PROPERTY	0	0	61	112	102	92	82	72	61	51	51	51	51	51	51	51	51
DEPRECIATION PERSONAL PROPERTY	0	0	4,676	6,858	5,246	6,546	6,546	0	0	0	0	0	0	0	0	0	0
GENERAL AND ADMINISTRATIVE	0	0	50	120	134	152	171	161	150	144	153	162	172	182	193	205	217
INSURANCE	0	0	196	225	238	252	268	284	301	319	338	358	380	402	427	452	479
AMORTIZATION																	
RECREATION COSTS	0	0	128	255	255	255	255	128	0	0	0	0	0	0	0	0	0
LOAN FEES	0	0	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20
DEFERRED INTEREST	0	0	15	30	30	30	30	30	30	30	30	30	15	0	0	0	0
TOTAL OPERATING EXPENSES	15	103	7,857	13,354	13,404	13,791	14,262	7,933	8,224	8,699	9,214	9,741	10,326	10,926	11,577	12,267	12,999
INCOME (LOSS) FROM OPERATIONS	-15	-103	-3,778	-1,774	-1,350	-826	-603	6,503	7,135	7,596	7,564	8,007	8,539	8,994	9,360	9,943	9,197
INTEREST EXPENSE																	
TERM LOAN	0	0	1,445	3,303	3,237	3,149	3,040	2,928	2,752	2,558	2,339	2,092	1,808	1,479	1,107	682	228
WORKING CAPITAL	0	0	78	149	197	114	96	73	47	18	0	0	0	0	0	0	0
DURING CONSTRUCTION	178	1,226	1,252	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTEREST EXPENSE	178	1,226	3,225	3,452	3,371	3,263	3,136	2,992	2,797	2,575	2,339	2,092	1,808	1,479	1,107	682	228
INCOME (LOSS)	-193	-1,329	-6,803	-5,226	-4,721	-4,191	-3,739	3,522	4,338	5,021	5,225	5,915	6,732	7,515	8,253	9,261	8,970
INCREASE IN ACCOUNTS RECEIVABLE	0	0	-773	-333	-46	-79	-77	-76	-91	-96	-42	-94	-107	-153	-99	-124	1
INCREASE IN ACCOUNTS PAYABLE	0	0	361	24	25	27	29	27	29	31	34	36	39	41	43	46	48
TAXABLE INCOME (LOSS)	$-193	$-1,329	$-7,215	$-5,534	$-4,742	$-4,244	$-3,785	$3,473	$4,276	$4,742	$5,212	$5,855	$6,664	$7,424	$8,199	$9,183	$9,021

TABLE 15. PROJECTED STATEMENT OF CASH FLOW. THIRD-PARTY DEVELOPER, 15-MEGAWATT CASE.

	1995	1996	1997	1998	1999	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
TAXABLE INCOME/(LOSS)	$-193	$-1,329	$-7,215	$-5,534	$-4,742	$-4,244	$-3,728	$3,473	$4,276	$4,962	$5,212	$5,955	$6,664	$7,454	$8,198	$9,189	$9,629
DEPRECIATION	0	0	4,737	6,979	6,648	6,638	6,628	72	61	51	51	51	51	51	51	51	51
AMORTIZATION	0	0	152	305	305	305	305	177	59	59	59	59	35	29	29	29	29
CONST PERIOD INT EXP	193	1,329	1,389	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCREASE IN INVENTORY	0	0	353	-44	-46	-49	-52	-55	-58	-62	-66	-70	-74	-78	-83	-88	-93
CASH FLOW FROM OPERATIONS	0	0	-584	1,697	2,163	2,650	3,153	3,667	4,329	5,001	5,248	5,886	6,676	7,447	8,186	9,166	8,998
PRINCIPAL REPAYMENT TERM LOAN	0	0	0	-421	-595	-738	-927	-1,095	-1,348	-1,641	-1,769	-2,022	-2,359	-2,696	-3,338	-3,496	-3,530
PRINCIPAL REPAYMENT WORKING CAP	0	0	0	-113	-128	-146	-166	-189	-215	-244	0	0	0	0	0	0	0
CASH GENERATED DURING PERIOD	0	0	-584	1,164	1,440	1,747	2,060	2,383	2,766	3,156	3,479	3,864	4,317	4,751	5,153	5,670	5,468
DISTRIBUTIONS FROM RESERVES	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200
WORKING CAPITAL BORROWING	0	0	1,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH BALANCE BEFORE DISTRIBUTION	0	0	616	1,364	1,640	1,947	2,260	2,583	2,966	3,356	3,679	4,064	4,517	4,951	5,353	5,870	5,668
CASH DISTRIBUTIONS TO																	
THIRD-PARTY	0	0	-208	-582	-724	-873	-1,030	-1,192	-1,383	-1,578	-1,739	-1,932	-2,159	-2,375	-2,577	-2,835	-2,749
CORPORATE PARTNER	0	0	-208	-582	-724	-873	-1,030	-1,192	-1,383	-1,578	-1,739	-1,932	-2,159	-2,375	-2,577	-2,835	-2,749
TOTAL CASH DISTRIBUTIONS	0	0	-416	-1,164	-1,447	-1,747	-2,060	-2,383	-2,766	-3,156	-3,479	-3,864	-4,317	-4,751	-5,153	-5,670	-5,498
ENDING CASH BALANCE	0	0	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
DEBT COVERAGE RATIO	0.00	0.00	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.94	2.04	2.14	2.24	2.36	2.47

TABLE 16. PROJECTED TAXABLE INCOME (LOSS), DISTRIBUTION OF AVAILABLE CASH AND ALOOCATIONS OF INCOME TAX BENEFITS (REQUIREMENTS) TO EQUITY PARTNERS. THIRD-PARTY DEVELOPER, 15-MEGAWATT CASE.

(In Thousands)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
TAXABLE INCOME (LOSS)	$-193	$-1,329	$-7,215	$-5,534	$-5,742	$-4,247	$-3,725	$3,433	$4,274	$4,962	$5,212	$5,855	$6,664	$7,454	$8,195	$9,185	$9,020
FED DEPRECIATION	0	0	4,737	6,572	6,648	6,638	6,625	72	61	51	51	51	51	51	51	51	51
STATE DEPRECIATION	0	0	-405	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214	-1,214
STATE TAXABLE INCOME (LOSS)	-193	-1,329	-3,066	222	692	1,179	1,404	2,329	3,122	3,797	4,340	4,698	5,499	6,289	7,033	8,028	7,855
STATE TAX BENEFITS (REQMTS)	17	119	276	-20	-62	-105	-130	-208	-279	-335	-382	-419	-485	-562	-628	-716	-702
FEDERAL TAXABLE INCOME (LOSS)	-176	-1,210	-6,940	-5,554	-4,803	-4,349	-3,672	3,345	3,996	4,623	4,851	5,436	6,173	6,892	7,570	8,467	8,319
NET AFTER TAX BENEFITS																	
FED TAX BENEFITS (REQMTS)	$82	$557	$3,192	$2,555	$2,211	$2,000	$1,754	$-1,532	$-1,839	$-2,127	$-2,231	$-2,500	$-2,839	$-3,171	$-3,482	$-3,895	$-3,826
STATE TAX BENEFITS (REQMTS)	17	119	276	-20	-62	-105	-130	-206	-279	-339	-382	-429	-491	-552	-628	-716	-702
CASH DISTRIBUTION (REQMTS)	0	0	436	1,164	1,447	1,747	2,060	2,353	2,766	3,356	3,479	3,864	4,337	4,751	5,152	5,672	5,496
INVESTMENT TAX CREDITS	632	2,050	621	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAX CREDITS	416	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	$1,140	$2,725	$4,505	$3,499	$3,595	$3,642	$3,684	$573	$649	$690	$866	$945	$987	$1,029	$1,042	$1,059	$974
DISTRIBUTION																	
EQUITY PARTNERS SHARE	$1,140	$2,725	$4,505	$3,499	$3,595	$3,642	$3,684	$573	$649	$690	$866	$945	$987	$1,029	$1,042	$1,059	$974
3-RD PARTY CARRIED INTEREST	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	$1,140	$2,725	$4,505	$3,499	$3,595	$3,642	$3,684	$573	$649	$690	$866	$945	$987	$1,029	$1,042	$1,059	$974
EQUITY INVESTMENT	$-2,473	$-8,116	$-3,726	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET AFTER TAX BENEFITS	1,140	2,725	4,505	3,499	3,595	3,642	3,684	573	649	690	866	945	987	1,029	1,042	1,059	974
NET CASH FLOW	$-1,336	$-5,391	$779	$3,499	$3,595	$3,642	$3,684	$573	$649	$690	$866	$945	$987	$1,029	$1,042	$1,059	$974
EQUITY PARTNERS																	
INTERNAL RATE OF RETURN	0.00%	0.00%	0.00%	0.00%	7.54%	20.44%	27.58%	26.42%	29.03%	29.50%	29.95%	30.31%	30.58%	30.77%	30.93%	31.07%	31[illegible]
NET PRESENT VALUE AT [illegible] DISCOUNT RATE	-1,336	-6,151	-5,514	-2,981	-394	1,573	3,341	3,646	3,998	4,137	4,442	4,714	4,947	5,206	5,412	5,607	5,764

TABLE 17. PROJECTED STATEMENT OF OPERATIONS - GAAP BASIS. THIRD-PARTY DEVELOPER, 15-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
REVENUES																	
ENERGY PAYMENT	0	0	$4,079	$11,581	$12,654	$12,845	$13,659	$14,434	$15,371	$16,295	$16,778	$17,768	$18,845	$19,920	$20,937	$22,219	$22,194
TOTAL REVENUES	0	0	4,079	11,581	12,654	12,845	13,659	14,434	15,371	16,295	16,778	17,768	18,845	19,920	20,937	22,219	22,194
OPERATING EXPENSES																	
WOOD FUEL SUPPLY	0	0	1,721	3,628	3,846	4,077	4,321	4,581	4,855	5,147	5,456	5,783	6,130	6,498	6,887	7,301	7,739
FLUID BED MATERIAL	0	0	33	73	74	79	83	88	94	99	105	112	118	125	133	141	149
UTILITIES AND ASH DISPOSAL	0	0	98	186	197	209	221	234	248	263	279	296	313	332	352	373	396
OPERATIONS & MAINTENANCE LABOR	0	0	576	1,222	1,293	1,371	1,453	1,540	1,633	1,731	1,835	1,945	2,061	2,185	2,316	2,455	2,602
REPAIRS AND MAINTENANCE	0	0	299	631	669	709	751	796	844	895	948	1,005	1,066	1,129	1,197	1,269	1,345
DEPRECIATION	0	0	529	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058
GENERAL AND ADMINISTRATIVE	0	0	59	125	134	142	171	141	151	141	153	162	172	182	193	205	217
INSURANCE	0	0	186	225	238	252	268	284	301	319	338	358	380	402	427	452	477
AMORTIZATION																	
PRE OPERATION COSTS	0	0	25	50	50	50	50	50	50	50	50	50	50	50	50	50	50
LOAN FEES	0	0	13	29	29	29	29	29	29	29	29	29	29	29	29	29	29
TOTAL OPERATING EXPENSES	0	0	3,455	7,257	7,579	7,976	8,397	8,812	9,253	9,726	10,242	10,789	11,368	11,983	12,634	13,329	14,056
INCOME (LOSS) BEFORE INT EXP	0	0	624	4,323	4,475	4,869	5,262	5,624	6,118	6,569	6,536	6,980	7,477	7,937	8,303	8,886	8,140
INTEREST EXPENSE																	
INTEREST EXPENSE																	
TERM LOAN	0	0	1,665	3,303	3,237	3,145	3,048	2,938	2,759	2,558	2,339	2,092	1,808	1,479	1,107	682	225
WORKING CAPITAL	0	0	78	149	134	116	96	73	47	18	0	0	0	0	0	0	0
TOTAL INTEREST EXPENSE	0	0	1,743	3,452	3,371	3,261	3,144	2,982	2,797	2,575	2,339	2,092	1,808	1,479	1,107	682	225
PRETAX INCOME (LOSS)	0	0	$-1,119	$871	$1,104	$1,608	$2,118	$2,642	$3,321	$3,994	$4,198	$4,887	$5,670	$6,458	$7,196	$8,204	$7,913
THIRD-PARTY DEVELOPER	0	0	$-544	$461	$552	$812	$1,263	$1,321	$1,661	$1,997	$2,099	$2,444	$2,845	$3,229	$3,598	$4,102	$3,956
CORPORATE PARTNER	0	0	-544	461	552	812	1,263	1,321	1,661	1,997	2,099	2,444	2,845	3,229	3,598	4,102	3,956
PRETAX INCOME (LOSS)	0	0	$-1,119	$871	$1,104	$1,623	$2,126	$2,642	$3,321	$3,994	$4,198	$4,887	$5,670	$6,458	$7,196	$8,204	$7,913

TABLE 18. PROJECTED BALANCE SHEETS. THIRD-PARTY DEVELOPER, 15-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CASH	0	0	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
ACCOUNTS RECEIVABLE	0	0	793	1,126	1,172	1,251	1,328	1,404	1,494	1,564	1,631	1,727	1,834	1,937	2,036	2,159	2,158
INVENTORY	0	400	727	770	817	866	918	973	1,031	1,093	1,158	1,228	1,302	1,380	1,463	1,550	1,643
TOTAL CURRENT ASSETS	0	400	1,720	2,096	2,189	2,316	2,446	2,576	2,725	2,977	2,992	3,155	3,336	3,516	3,698	3,910	4,001
PLANT AND EQUIPMENT	6,403	31,425	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835	37,835
ACCUMULATED DEPRECIATION	0	0	-529	-1,587	-2,645	-3,704	-4,762	-5,820	-6,878	-7,936	-8,994	-10,052	-11,111	-12,169	-13,227	-14,285	-15,343
NET OF PLANT & EQUIPMENT	6,403	31,425	36,306	35,448	34,399	33,332	32,273	31,215	30,157	29,099	28,041	26,983	25,925	24,966	23,808	22,750	21,692
UNAMORTIZED PREOPERATION COST	1,500	1,500	1,425	1,425	1,375	1,325	1,275	1,225	1,175	1,125	1,075	1,025	975	925	875	825	775
UNAMORTIZED LOAN FEES	300	300	298	278	253	230	219	192	173	153	138	113	98	78	58	38	19
TOTAL ASSETS	$8,203	$33,625	$39,791	$39,229	$38,253	$37,253	$36,254	$35,216	$34,229	$33,251	$32,235	$31,273	$30,325	$29,378	$28,431	$27,515	$26,478
ACCOUNTS PAYABLE	0	0	$381	$405	$430	$456	$485	$512	$541	$572	$607	$648	$682	$722	$766	$812	$860
WORKING CAPITAL LOAN	0	0	1,200	1,267	959	814	648	459	244	0	0	0	0	0	0	0	0
TERM LOAN-CURRENT	0	0	0	590	758	927	1,095	1,348	1,561	1,769	2,222	2,359	2,494	3,033	3,496	3,500	0
TOTAL CURRENT LIABILITIES	0	0	1,581	2,062	2,147	2,197	2,228	2,319	2,366	2,341	2,829	3,007	3,178	3,755	4,262	4,312	860
TERM LOAN-NONCURRENT	5,725	23,331	25,613	24,654	23,946	22,919	21,924	20,476	18,673	17,104	15,084	12,725	10,529	6,996	3,500	0	0
THIRD-PARTY EQUITY	1,239	5,297	6,398	6,276	6,155	6,043	6,076	6,256	6,483	6,902	7,261	7,773	8,459	9,313	10,335	11,681	12,809
CORPORATE PARTNER EQUITY	1,239	5,297	6,398	6,276	6,155	6,043	6,076	6,256	6,483	6,902	7,261	7,773	8,459	9,313	10,335	11,681	12,809
TOTAL EQUITY	2,478	10,594	12,795	12,553	12,311	12,087	12,152	12,511	12,966	13,804	14,523	15,546	16,919	18,626	20,669	23,363	25,618
TOTAL LIABILITIES AND EQUITY	$8,203	$33,625	$39,791	$39,229	$38,253	$37,253	$36,254	$35,216	$34,229	$33,251	$32,235	$31,273	$30,325	$29,378	$28,431	$27,515	$26,478

TABLE 19. UTILITY AVOIDED COST SCHEDULE. THIRD-PARTY DEVELOPER, 15-MEGAWATT CASE.

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
UTILITY AVOIDED COST	7.12	10 11	10 52	11 23	11 92	12 60	13 42	14.22	14 64	15.51	16.47	17 39	18.27	19.30	19.37

NOTE: COST OF ENERGY TO EGLIN AFB TO MAKE "THIRD-PARTY" OPERATION FEASIBLE FOR A 15-MW_e PLANT.

TABLE 20. PROJECTED STATEMENT OF OPERATIONS - GAAP BASIS. MILCON DEVELOPER, 25-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
REVENUES																	
ENERGY PAYMENT	0	0	$4,614	$8,859	$9,499	$10,249	$10,685	$11,303	$11,968	$12,642	$13,422	$14,227	$15,088	$15,985	$16,944	$17,961	$19,039
TOTAL REVENUES	0	0	4,614	8,859	9,499	10,249	10,685	11,303	11,968	12,642	13,422	14,227	15,088	15,985	16,944	17,961	19,039
OPERATING EXPENSES																	
WOOD FUEL SUPPLY	0	0	2,959	5,341	6,403	6,788	7,195	7,627	8,084	8,569	9,083	9,628	19,296	10,819	11,468	12,156	12,885
FLUID BED MATERIAL	0	0	32	70	74	79	83	88	94	99	105	112	118	125	133	141	149
UTILITIES AND ASH DISPOSAL	0	0	98	186	197	208	221	234	248	263	279	296	313	332	352	373	396
OPERATIONS & MAINTENANCE LABOR	0	0	714	1,314	1,404	1,781	1,883	1,971	2,026	2,147	2,276	2,413	2,557	2,711	2,873	3,046	3,229
REPAIRS AND MAINTENANCE	0	0	435	921	977	1,035	1,097	1,163	1,233	1,307	1,385	1,468	1,557	1,650	1,749	1,854	1,965
DEPRECIATION	0	0	594	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187
GENERAL AND ADMINISTRATIVE	0	0	53	127	142	161	192	178	159	153	162	172	182	199	205	217	230
AMORTIZATION.																	
TOTAL OPERATING EXPENSES	0	0	4,763	10,846	10,585	11,159	11,768	12,381	13,031	13,726	14,479	15,276	16,121	17,017	17,967	18,974	20,041
INCOME (LOSS) BEFORE INT EXP	0	0	-152	-1,187	-1,086	-1,091	-1,084	-1,078	-1,071	-1,064	-1,057	-1,049	-1,041	-1,032	-1,023	-1,013	-1,002
INTEREST EXPENSE																	
INTEREST EXPENSE																	
PRETAX INCOME/(LOSS)	0	0	$-152	$-1,187	$-1,086	$-1,091	$-1,084	$-1,078	$-1,071	$-1,064	$-1,057	$-1,049	$-1,041	$-1,032	$-1,023	$-1,013	$-1,002
CORPORATE PARTNER	0	0	-152	-1,187	-1,086	-1,091	-1,084	-1,078	-1,071	-1,064	-1,057	-1,049	-1,041	-1,032	-1,023	-1,013	-1,002
PRETAX INCOME/(LOSS)	0	0	$-152	$-1,187	$-1,086	$-1,091	$-1,084	$-1,078	$-1,071	$-1,064	$-1,057	$-1,049	$-1,041	$-1,032	$-1,023	$-1,013	$-1,002

TABLE 21. PROJECTED BALANCE SHEETS. MILCON-DEVELOPER, 25-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
ACCOUNTS RECEIVABLE	0	0	897	841	923	979	1,039	1,099	1,163	1,231	1,305	1,383	1,466	1,554	1,647	1,746	1,851
INVENTORY	0	400	1,201	1,273	1,350	1,430	1,516	1,607	1,704	1,806	1,914	2,029	2,151	2,280	2,417	2,562	2,715
TOTAL CURRENT ASSETS	0	400	2,098	2,134	2,273	2,409	2,555	2,706	2,866	3,037	3,219	3,412	3,617	3,834	4,064	4,308	4,566
PLANT AND EQUIPMENT	7,116	31,250	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550	41,550
ACCUMULATED DEPRECIATION	0	0	-294	-1,781	-2,968	-4,155	-5,342	-6,529	-7,716	-8,904	-10,091	-11,278	-12,465	-13,652	-14,839	-16,026	-17,214
NET OF PLANT & EQUIPMENT	7,116	31,250	40,956	39,769	38,582	37,395	36,208	35,021	33,834	32,646	31,459	30,272	29,085	27,898	26,711	25,524	24,336
TOTAL ASSETS	$7,116	$31,650	$43,055	$41,904	$40,855	$39,804	$38,763	$37,727	$36,700	$35,683	$34,678	$33,684	$32,702	$31,732	$30,775	$29,832	$28,903
ACCOUNTS PAYABLE	0	0	576	612	649	689	732	774	818	866	918	973	1,031	1,093	1,159	1,228	1,302
TOTAL CURRENT LIABILITIES	0	0	576	612	649	689	732	774	818	866	918	973	1,031	1,093	1,159	1,228	1,302
CORPORATE PARTNER EQUITY	7,116	31,650	42,478	41,292	40,206	39,115	38,031	36,953	35,882	34,817	33,761	32,711	31,671	30,639	29,616	28,603	27,601
TOTAL EQUITY	7,116	31,650	42,478	41,292	40,206	39,115	38,031	36,953	35,882	34,817	33,761	32,711	31,671	30,639	29,616	28,603	27,601
TOTAL LIABILITIES AND EQUITY	$7,116	$31,650	$43,055	$41,904	$40,855	$39,804	$38,763	$37,727	$36,700	$35,683	$34,678	$33,684	$32,702	$31,732	$30,775	$29,832	$28,903

TABLE 22. UTILITY AVOIDED COST SCHEDULE. MILCON-DEVELOPER, 25-MEGAWATT CASE.

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
UTILITY AVOIDED COST	4.33	4.64	4.97	5.27	5.60	5.95	6.25	6.63	7.03	7.45	7.90	8.37	8.87	9.41	9.97

TABLE 23. PROJECTED STATEMENT OF OPERATIONS - GAAP BASIS. MILCON-DEVELOPER, 15-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
REVENUES																	
ENERGY PAYMENT	0	0	2,531	5,963	6,265	6,658	7,067	7,469	7,897	8,357	8,858	9,398	9,953	10,550	11,183	11,854	12,565
TOTAL REVENUES	0	0	2,531	5,963	6,265	6,658	7,067	7,469	7,897	8,357	8,858	9,398	9,953	10,550	11,183	11,854	12,565
OPERATING EXPENSES																	
WOOD FUEL SUPPLY	0	0	1,712	3,629	3,847	4,077	4,322	4,581	4,856	5,148	5,456	5,784	6,131	6,499	6,889	7,302	7,740
FLUID BED MATERIAL	0	0	33	70	74	79	83	88	94	99	105	112	118	125	133	141	149
UTILITIES AND ASH DISPOSAL	0	0	88	186	197	208	221	234	248	263	279	296	314	332	352	373	396
OPERATIONS & MAINTENANCE LABOR	0	0	576	1,220	1,293	1,371	1,453	1,540	1,633	1,731	1,835	1,945	2,062	2,186	2,317	2,456	2,603
REPAIRS AND MAINTENANCE	0	0	298	631	669	709	751	796	844	895	948	1,005	1,066	1,129	1,197	1,269	1,345
DEPRECIATION	0	0	508	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016
GENERAL AND ADMINISTRATIVE EXPENSES	0	0	76	120	128	152	171	161	159	196	173	162	172	185	195	205	217
TOTAL OPERATING EXPENSES	0	0	3,264	6,873	7,225	7,612	8,018	8,417	8,841	9,295	9,792	10,319	10,877	11,469	12,096	12,761	13,465
INCOME (LOSS) BEFORE INT EXP	0	0	-732	-907	-964	-954	-951	-947	-943	-939	-934	-929	-924	-919	-913	-907	-900
INTEREST EXPENSES																	
INTEREST EXPENSE.																	
PRETAX INCOME(LOSS)	0	0	$-732	$-907	$-964	$-954	$-951	$-947	$-943	$-939	$-934	$-929	$-924	$-919	$-913	$-907	$-900
CORPORATE PARTNER	0	0	-732	-907	-964	-954	-951	-947	-943	-939	-934	-929	-924	-919	-913	-907	-900
PRETAX INCOME(LOSS)	0	0	$-732	$-907	$-964	$-954	$-951	$-947	$-943	$-939	$-934	$-929	$-924	$-919	$-913	$-907	$-900

TABLE 24. PROJECTED BALANCE SHEETS. MILCON-DEVELOPER, 15-MEGAWATT CASE.

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
ACCOUNTS RECEIVABLE	0	0	492	580	659	647	687	726	768	812	861	913	968	1,026	1,087	1,152	1,222
INVENTORY	0	400	727	771	817	866	918	973	1,031	1,093	1,159	1,229	1,302	1,380	1,463	1,551	1,644
TOTAL CURRENT ASSETS	0	400	1,219	1,350	1,476	1,513	1,605	1,699	1,799	1,906	2,020	2,141	2,270	2,406	2,550	2,703	2,865
PLANT AND EQUIPMENT	6,087	26,647	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550	35,550
ACCUMULATED DEPRECIATION	0	0	-508	-1,524	-2,539	-3,555	-4,571	-5,586	-6,602	-7,618	-8,634	-9,649	-10,665	-11,681	-12,696	-13,712	-14,728
NET PLANT & EQUIPMENT	6,087	26,647	35,042	34,026	33,011	31,995	30,979	29,964	28,948	27,932	26,916	25,901	24,885	23,869	22,854	21,838	20,822
TOTAL ASSETS	6,087	27,047	36,261	35,377	34,487	33,508	32,584	31,663	30,747	29,838	28,936	28,042	27,155	26,275	25,404	24,541	23,687
ACCOUNTS PAYABLE	0	0	0363	0386	0410	0435	0462	0488	0516	0546	0579	0613	0650	0689	0730	0774	0821
TOTAL CURRENT LIABILITIES	0	0	363	386	410	435	462	488	516	546	579	613	650	689	730	774	821
CORPORATE PARTNER EQUITY	6,087	27,047	35,898	34,991	34,077	33,073	32,122	31,174	30,231	29,292	28,358	27,429	26,505	25,586	24,673	23,767	22,867
TOTAL EQUITY	6,087	27,047	35,898	34,991	34,077	33,073	32,122	31,174	30,231	29,292	28,358	27,429	26,505	25,586	24,673	23,767	22,867
TOTAL LIABILITIES AND EQUITY	6,087	27,047	36,261	35,377	34,487	33,508	32,584	31,663	30,747	29,838	28,936	28,042	27,155	26,275	25,404	24,541	23,687

TABLE 25. UTILITY AVOIDED COST SCHEDULE. MILCON-DEVELOPER, 25-MEGAWATT CASE.

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
UTILITY AVOIDED COST	4.42	5.20	5.47	5.91	6.17	6.52	6.89	7.29	7.73	8.20	8.69	9.21	9.76	15.35	18.97

4. Current and Forecasted Gulf Power Costs

The economic impact of implementing any of the previously detailed operating forecasts must be reviewed as compared to the existing power purchase mechanism now in place for Eglin Air Force Base. Tables 26 and 27 present the cumulative result of detailed computer modeling analysis of the electric bills from both the Valparaiso and Westgate substations from January 1983 through July 1984. Calendar Year 1984 average electricity and capacity requirements for the entire base were derived from that source.

As the average energy and demand requirements of Eglin Air Force Base are reduced by the addition of a 15-MW_e or 25-MW_e source, the cost of service from Gulf Power is reduced, although this relationship is not directly proportional, due to the independent reaction of energy costs versus demand costs. Tables 28 through 31 present the detailed electric fuel analysis is a derivation of future costs and their escalation over time, assuming a 15- or 25-MW_e plant becomes available to the power grid in mid-1987.

Assumptions used in this program are listed on the top of the first page of each case, as well as annual escalation rates for each of those variables. Escalation rates were derived from a variety of industry sources and are considered estimates, rather than forecasts.

5. Summary

Economic analyses were run on two plant sizes; both were base-loaded so as to be able to be operated at maximum efficiency. The smaller plant, at approximately 15-MW_e, was sized to accommodate the needs of the main base while the larger, at approximately 25-MW_e, is sized to accommodate the needs of the entire base. Both were also sized so as not to trigger a higher rate from Gulf Power for peak needs.

TABLE 26. 1984 ESCALATED COST CALCULATION WITHOUT BIOMASS ECONOMY.

BASE — EGLIN AIR FORCE BASE VALPARAISO AND NESTGATE SUBSTATIONS

VARIABLE INPUT SECTION - 1984 ESTIMATED ANNUAL AVERAGES

1 TOTAL KWH USED	=	370,000,000	7. AVG MAX KW DEMAND	44,000.00	
2 ON PEAK % OF AVG TOTAL KWH USED	=	29%	8 AVG PEAK KW DEMAND	42,000.00	
3 ON PEAK CENTS/KWH	=	$0 0200	9 $/KW MAX MAx DEMAND	$3 08	
4. OFF PEAK CENTS/KWH	=	$0 0250	10. $/KW PEAK MAx DEMAND	$3.18	
5 FUEL COST ON PEAK	=	$0 0300	11 TLO ANNUAL $/KW MAX DEMAND	$0.78	
6 FUEL COST OFF PEAK	=	$0 0252	12 NUMBER OF MONTHS IN YEAR	12	

ANNUAL ESCALATIONS

1	5.00%
2	0.00%
3	6 20%
4	6 50%
5	2.00%
6	2 00%
7	1.50%
8	1.50%
9	0.00%
10	0.00%
11	0.00%

CONTRACT CAPACITY $1.0 MWe

	AVG KWH USED	COST OF ENERGY			CURRENT COST OF FUEL		TOTAL COSTS
TOTAL	370,000,000						
ON PEAK	107,300,000	$0 020 /KWH	$2,146,000	PLUS @	$0.0300	$3,219,000	$5,365,000
OFF PEAK	262,700,000	$0 005 /KWH	$1,313,500	PLUS @	$0 0252	$6,882,740	$8,196,240

	AVG KW DEMAND				TRANSMISSION LINE DISCOUNT		
MAXIMUM	44,000	@	3 08 $/Kw	$135,520 TIMES 12 MOS LESS @	0 78 X 12 MOS	$1,214,400	$1,214,400
ON PEAK	42,000	@	3 18 $/KW	$133,560 TIMES 12 MOS.		$1,602,720	$1,602,720

ESTIMATED TOTAL COSTS FROM GULF POWER - 1984	$16,378,360
ESTIMATED CENTS PER KW/H - 1984	$0.044266

TABLE 27. 1985 ESCALATED COST CALCULATION WITHOUT BIOMASS ECONOMY.

BASE

PROJECTED 1985 ANNUAL AVERAGES — EGLIN AIR FORCE BASE VALPARAISO AND NESTGATE SUBSTATIONS

1	303,509,200	7	44,660 00	
2	29 001	8	42,630 00	
3	0 0212	9	3 98	
4	0 0053	10	3 18	
5	0 0306	11	0 78	
6	0 0267	12	12	

	AVG KWH USED		COST OF ENERGY			CURRENT COST OF FUEL			
TOTAL	308,509,200								
ON PEAK	112,443,200		0.0212 /KWH	$2,399,645	PLUS	@ $0.0306	$3,442,549		$5,842,194
OFF PEAK	275,335,200		0 0053 /KWH	$1,468,321	PLUS	@ $0 0267	$7,371,415		$8,839,736

	AVG KW DEMAND				TRANSMISSION LINE DISCOUNT		
MAXIMUM	44,363	@	3 58 MW	$127,553 TIMES 12 MOS LESS 3	3 78 X 12 MOS	$1,232,616	$1,232,616
ON PEAK	42,630	@	3 18 MW	$135,563 TIMES 12 MOS.		$1,626,761	$1,626,761

ESTIMATED TOTAL COSTS FROM GULF POWER - 1985	$17,540,154
ESTIMATED COSTS PER KWH - 1985	$0.0451[illegible]
ESTIMATED CENTS/ YEAR TO YEAR ESCALATION RATE	1 [illegible]
PROJECTED ELECTRIC COST YEAR TO YEAR ESCALATION RATE	7 [illegible]

TABLE 28. 1984 ESCALATED COST CALCULATION - 25-MEGAWATT PLANT.

25 MW — EGLIN AIR FORCE BASE - VALPARAISO AND WESTGATE SUBSTATIONS

VARIABLE INPUT SECTION - 1980 ESTIMATED ANNUAL AVERAGES

1	TOTAL KWH USED	• 177,500,000	7 AVG PAID KW DEMAND	20 000	
2	ON PEAK % OF AVG TOTAL KWH USED	• 29%	8 AVG PEAK KW DEMAND	16,000	
3	ON PEAK CENTS/KWH	• 10 0230	9 $/KW ASSD MWH DEMAND	93 00	
4	OFF PEAK CENTS/KWH	• 10 0050	10 $/KW PEAK MWH DEMAND	93 10	
5	FUEL COST ON PEAK	• 10 0300	11 TLD ANNUAL $/KW ASSD DEMAND	• 10 78	
6	FUEL COST OFF PEAK	• 10 0262	12 NUMBER OF MONTHS IN YEAR	• 12	

ANNUAL ESCALATIONS

1	5 00%
2	0.00%
3	6.20%
4	6.50%
5	2 00%
6	2 00%
7	1.50%
8	1 50%
9	0 00%
10	0 00%
11	0 00%

CONTRACT CAPACITY 61 0 MW

	AVG KWH USED		COST OF ENERGY			CURRENT COST OF FUEL		TOTAL COSTS
TOTAL	177,500,000							
ON PEAK	51,475,000		10 030 /KWH	$1,029,500	PLUS •	10.0300	$1,544,250	• $2,573,750
OFF PEAK	126,025,000		10 005 /KWH	$630,125	PLUS •	10.0262	$3,301,055	• $3,931,180

	AVG KW DEMAND				TRANSMISSION LINE DISCOUNT		
MAXIMUM	25,000	•	3 19 $/KW	$61,600 TIMES 12 MOS LESS •	0.78 X 12 MOS •	$552,000	$552,000
ON PEAK	10,000	•	3 19 $/KW	$57,240 TIMES 12 MOS.		$476,880	$476,880

ESTIMATED TOTAL COSTS FROM GULF POWER - 1984 — $7,744,610

ESTIMATED CENTS PER KWH - 1984 — 10 043632

TABLE 29. 1985 ESCALATED COST CALCULATION - 25-MEGAWATT PLANT.

1984

PROJECTED 1985 ANNUAL AVERAGES

1	184 375,000
2	39 163
3	0 02 2
4	3 0053
5	0 0364
6	3 0267

EGLIN AIR FORCE BASE VALPARAISO AND DESTIN SUBSTATIONS

7	20,300 00
8	10,270 00
9	3 00
10	3 10
11	0 70
12	12

	AVG KWH USED		COST OF ENERGY			CURRENT COST OF FUEL		
TOTAL	184,375,000							
ON PEAK	54,049,750		0 0212 /KWH	$1,147,795	PLUS	0 10 0306	$1,653,072	$2,801,067
OFF PEAK	130,326,250		0 0053 /KWH	$704 637	PLUS	0 10 0267	$3,536,287	$4,240,924

	AVG KW DEMAND				TRANSMISSION LINE DISCOUNT	
PARTIAL	20,300	0	3 00 $KW	$62,584 TIMES 12 MOS LESS 0	0 70 X 12 MOS =	$560,280
ON PEAK	10,270	0	3 10 $KW	$59,099 TIMES 12 MOS.		$697,183

	$560,280
	$697,183
ESTIMATED TOTAL COSTS FROM GULF POWER - 1985	$8,300,274
ESTIMATED CENTS PER KWH - 1985	10.044533
ASSUMED CENTS/KWH YEAR TO YEAR ESCALATION RATE	2 071%
ASSUMED ELECTRIC COST YEAR TO YEAR	7 175%

TABLE 30. 1984 ESCALATED COST CALCULATION - 15-MEGAWATT PLANT.

15MW EGLIN AIR FORCE BASE - SAN PARAISO AND WESTGATE SUBSTATIONS

VARIABLE INPUT SECTION	1984 ESTIMATED ANNUAL AVERAGES				ANNUAL ESCALATIONS	
1 TOTAL KWH USED	= 254,500,000	7 AVG MAX KW DEMAND	29,000		1	5.00%
2 ON PEAK % OF AVG TOTAL KWH USED	= 29%	8 AVG PEAK KW DEMAND	27,000		2	9.00%
3 ON PEAK CENTS/KWH	= $0.0230	9 $/KW MAX MON DEMAND	$3.00		3	6.20%
4 OFF PEAK CENTS/KWH	= $0.0050	10 $/KW PEAK MON DEMAND	$3.10		4	6.50%
5 FUEL COST ON PEAK	= $0.0360	11 TLO ANNUAL $/KW MAX DEMAND	= $0.70		5	7.00%
6 FUEL COST OFF PEAK	= $0.0262	12 NUMBER OF MONTHS IN YEAR	= 12		6	2.00%
					7	1.50%
					8	1.50%
					9	0.00%
					10	0.00%
					11	0.00%

CONTRACT CAPACITY 15.0 MW

	AVG KWH USED	COST OF ENERGY			CURRENT COST OF FUEL		TOTAL COSTS
TOTAL	254,500,000						
ON PEAK	73,805,000	$0.020 /KWH	$1,476,100	PLUS 0	$0.0360	$2,214,150	= $3,690,250
OFF PEAK	180,695,000	$0.005 /KWH	$903,475	PLUS 0	$0.0262	$4,734,209	= $5,637,684

	AVG KW DEMAND				TRANSMISSION LINE DISCOUNT	
MAXIMUM	29,000	@	3.00 $/KW	109,320 TIMES 12 MOS LESS 0	0.70 X 12 MOS =	$800,400
ON PEAK	27,000	@	3.10 $/KW	105,840 TIMES 12 MOS.		$1,030,320

	$800,400
	$1,030,320
TOTAL COSTS FROM GULF POWER	$11,158,654
ESTIMATED COSTS PER KWH - 1984	$0.0438345

TABLE 31. 1985 ESCALATED COST CALCULATION - 15-MEGAWATT PLANT.

15 MW

PROJECTED 1985 ANNUAL AVERAGES — EGLIN AIR FORCE BASE - VALPARAISO AND MILTGATE SUBSTATIONS

1	267,225,000	7	29,435.00
2	29.00%	8	27,405.00
3	0.0212	9	3.00
4	0.0053	10	3.10
5	0.0204	11	0.70
6	0.0267	12	12

	AVG KWH USED	COST OF ENERGY			CURRENT COST OF FUEL		
TOTAL	267,225,000						
ON PEAK	77,495,250	0.0212 /KWH	$1,645,999	PLUS @	10.0306	$2,371,353	$4,017,354
OFF PEAK	189,729,750	0.0053 /KWH	$1,010,311	PLUS @	10.0267	$5,070,338	$6,080,649

	AVG KW DEMAND				TRANSMISSION LINE DISCOUNT		
MAXIMUM	29,435	@	3.00 KW	990,660 TIMES 12 MOS LESS @	0.70 X 12 MOS =	1012,404	1012,404
ON PEAK	27,495	@	3.10 KW	907,140 TIMES 12 MOS,		$1,045,775	$1,045,775

ESTIMATED TOTAL COSTS FORM GULF POWER - 1985	$11,956,103
ESTIMATED CENTS PER KWH - 1985	10.044742
ASSUMED CENTS/KWH YEAR TO YEAR ESCALATION RATE	2.0453
ASSUMED ELECTRIC COST YEAR TO YEAR	7.1471

The analyses were run for both third-party-funded projects and for MILCON-financed projects. Under the third-party options, the plant would be designed, constructed, owned, and operated by a private corporation. Under this option, the United States Air Force would be required to provide the land for the plant and would be billed for its electrical consumption at the established rates. A long-term power sales contract would be negotiated between the United States Air Force and the private corporation. Under the MILCON-funded operation, the United States Air Force would, of course, fund the design, construction and the ongoing operation of the plant. In the analyses for this option, all operating costs were included, and the power rate was adjusted to cover the operating costs.

All of the preceding estimates and forecasts are summarized and compared in Tables 32 and 33 to help determine the most appropriate route in addressing the issue of the cost of electrical reliability in a national emergency.

Option 1 on Table 32 assumes no change in the existing source, and the estimated cost of electric power in 1984 is assumed to be the "base case" for these forecasts. For the years following, certain assumptions were made to recognize the dynamics of the current economic universe. Those per annum escalations include a 5-percent increase in the total average kWh consumed by the Base, a 3-percent increase in average peak demand, a 6-percent increase in average energy costs, and a 2-percent increase in fuel costs.

Option 2 adds the costs of purchasing 15-MW_e of electricity at 7,700 hours/year from the proposed third-party-owned plant to the cost of purchasing correspondingly reduced energy and capacity from Gulf Power.

Option 3 is identical to Option 2, except that 25-MW_e of power is being supplied by the third-party-owned plant.

Option 4 assumes that MILCON has paid for the construction and startup of a 15-MW_e plant and that electricity is being sold to the Base at "cost." Pretax operating losses shown on the projected statement of operations are attributable under generally accepted accounting principles to book

depreciation of plant and equipment and the continuous accumulation and reduction of receivables and payables, all of which has no effect on the cash break-even position of the proposed operation.

Option 5 is identical to Option 4, except that 25-MW_e of power is being supplied by the MILCON-owned plant.

It is obvious from an examination of these results that any MILCON involvement would be most advantageous; however, congressional approval for federal funding of such a construction project is a required condition for considering the viability of Options 4 or 5. In addition, no cost-of-funds was used in conjunction with the analysis of those options.

When comparing the third-party scenarios, it is evident that the economics of scale are important in deciding what size plant should be considered. The 25-MW_e plant can be built to deliver less expensive energy on a per/kWh basis, and can be operated by a proportionally smaller crew than the 15 -MW_e plant. Another important consideration is that beyond the repayment period of the term debt, a significant savings in the cost of electricity could be realized through renegotiation of the power purchase contract, as the return on the original investment has now been realized, and cash flows to the partners will have become very significant.

However, from a purely economic viewpoint, no option considered within the scope of this report compares with the forecasted cost of electricity now being delivered by Gulf Power. This utility is forecasting low fuel escalation over the foreseeable future, and does not need to increase its capacity through the construction of major new facilities. Our conclusion, therefore, is that unless there is an overriding reason why Eglin Air Force Base should incur an estimated additional $5 million per annum in electric costs, the present electrical interconnection systems should remain unchanged.

TABLE 32. EGLIN AIR FORCE BASE SUMMARY OF FORECASTED COSTS OF ELECTRIC POWER SOURCE ALTERNATIVES.

SUMMARY

	1985	1986	1ST 6MO 1987	2ND 6MO 1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
									(000'S)									
OPTION 1																		
370,000,000 KWHr GULF POWER	17,540	10,784	10,058	10,058	21,544	23,072	24,709	26,461	28,338	30,349	32,501	34,807	37,276	39,920	42,752	45,785	49,032	52,511
TOTAL ANNUAL COST OPTION 1	17,540	10,784	10,058	10,058	21,544	23,072	24,709	26,461	28,338	30,349	32,501	34,807	37,276	39,920	42,752	45,785	49,032	52,511
OPTION 2																		
115,500,000 KWHr 3RD PARTY	0	0	0	4,079	11,501	12,054	12,665	13,659	14,436	15,371	16,295	16,778	17,768	18,865	19,920	20,937	22,210	22,176
254,500,000 KWHr GULF POWER	0	0	0	6,863	14,707	15,759	16,885	18,092	19,385	20,770	22,255	23,845	25,549	27,375	29,332	31,428	33,675	36,082
TOTAL ANNUAL COST OPTION 2	0	0	0	10,942	26,208	27,813	29,750	31,751	33,821	36,141	38,550	40,623	43,317	46,240	49,252	52,365	55,885	58,278
OPTION 3																		
192,500,000 KWHr 3RD PARTY	0	0	0	6,574	15,251	16,136	17,104	18,244	19,295	20,536	21,773	22,556	23,884	25,354	26,786	28,187	29,098	30,127
177,500,000 KWHr GULF POWER	0	0	0	4,767	10,218	10,951	11,737	12,579	13,482	14,449	15,486	16,597	17,787	19,064	20,431	21,897	23,469	25,152
TOTAL ANNUAL COST OPTION 3	0	0	0	11,341	25,469	27,087	28,921	30,823	32,777	34,985	37,259	39,153	41,671	44,418	47,217	50,084	53,567	55,279
OPTION 4																		
115,500,000 KWHr MIL-CON	0	0	0	2,531	5,963	6,265	2,531	5,963	6,265	2,531	5,963	6,265	2,531	5,963	6,265	2,531	5,963	6,265
254,500,000 KWHr GULF POWER	0	0	0	6,863	14,707	15,759	16,885	18,092	19,385	20,770	22,255	23,845	25,549	27,375	29,332	31,428	33,675	36,082
TOTAL ANNUAL COST OPTION 4	0	0	0	9,394	20,670	22,024	19,416	24,055	25,650	23,301	28,218	30,110	28,080	33,338	35,597	33,959	39,638	42,347
OPTION 5																		
192,500,000 KWHr MIL-CON	0	0	0	4,614	8,059	9,499	10,069	10,685	11,303	11,960	12,662	13,422	14,227	15,080	15,985	16,944	17,961	19,039
177,500,000 KWHr GULF POWER	0	0	0	4,767	10,218	10,951	11,737	12,579	13,482	14,449	15,486	16,597	17,787	19,064	20,431	21,897	23,469	25,152
TOTAL ANNUAL COST OPTION 5	0	0	0	9,381	19,077	20,450	21,806	23,264	24,785	26,407	28,148	30,019	32,014	34,144	36,416	38,841	41,430	44,191

TABLE 33. USAF RETURN BASED ON ENERGY SAVINGS.

		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OPTION 1		0	0	10,058	21,544	23,072	24,709	26,461	28,338	30,849	32,501	34,807	37,276	39,920	42,752	45,785	49,032	52,511
OPTION 5		0	0	9,381	19,077	20,450	21,806	23,264	24,785	26,409	28,148	30,019	32,014	34,144	36,416	38,841	41,430	44,191
SAVINGS		0	0	677	2,467	2,622	2,903	3,197	3,554	3,940	4,354	4,788	5,262	5,777	6,336	6,943	7,603	8,319
EQUITY EXPENDITURES		(7,116)	(24,534)	(10,980)														
NET CASH FLOW		(7,116)	(24,534)	(10,303)	2,467	2,622	2,903	3,197	3,554	3,940	4,354	4,788	5,262	5,777	6,336	6,943	7,603	8,319
RETURN ESTIMATE	10 00%																	
RATE OF RETURN					-03 15%	-50 95%	-42 00%	-30.18%	-21 61%	-15 21%	-10 33%	-6 52%	-3 49%	-1.05%	0 96%	2 62%	4 01%	5 20%
DISCOUNT RATE	12 00%																	
NET PRESENT VALUE		(6,354)	(25,712)	(33,245)	(31,677)	(30,190)	(28,719)	(27,278)	(25,837)	(24,417)	(23,015)	(21,630)	(20,288)	(18,964)	(17,660)	(16,399)	(15,159)	(13,947)

SECTION V
CONCLUSIONS AND RECOMMENDATIONS

A. GENERAL

The data developed in the earlier sections of the report indicate that biomass fuel is available in sufficient quantity and at such prices as to permit the operation of an electrical generating plant at Eglin AFB.

B. CONCLUSIONS

Based upon commonly used financial criteria, the construction and operation of either a 25-MW_e or 15-MW_e electrical generating plant would not be in the best interest of the Government. While plants of that size built and operated with MILCON funding would indeed reduce the electrical energy costs of the base, the indicated rate of return on the required investment would be difficult to defend on purely economic bases.

C. RECOMMENDATIONS

It is recommended that no further action should be taken to implement the Biomass Energy Island concept, unless noneconomic issues such as energy security in a national emergency can justify the capital expenditure.

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APPENDIX A

HEAT AND MASS BALANCE

25-MW PLANT AND 15-MW PLANT

STEAM CYCLE HEAT AND MASS BALANCE
EGLIN AFB BIOMASS ENERGY STUDY

SUMMARY:		DESIGN	
FUEL REQUIRED. TONS/HR	41.4	41.4	41.4
FUEL HEATING VALUE. BTU/LB (DRY)	8,500.00	8,500.00	8,500.00
MOISTURE CONTENT OF FUEL. % WB:	47.00%	47.00%	47.00%
BOILER DUTY. MM BTU/HR:	261.02	261.02	261.02
STEAM TURBINE BACK PRESSURE. " HgA	2.0	2.5	3.0
GROSS POWER OUTPUT. MW:	27.60	27.18	26.84
PARASITIC LOAD. MW	2.18	2.18	2.18
NET POWER OUTPUT. MW	25.42	[illegible]	24.66
STEAM TURBINE			
EXTRACTION EFFICIENCY. %	80.00%	80.00%	80.00%
CONDENSING EFFICIENCY. %	83.00%	83.00%	83.00%
THROTTLE FLOW. LB/HR	216,000.00	216,000.00	216,000.00
P. PSIA	1,250.00	1,250.00	1,250.00
T. F	950.00	950.00	950.00
h. Btu/LB	1,468.60	1,468.60	1,468.60
GLAND SEAL LEAK. LB/HR	1,080.00	1,080.00	1,080.00
P. PSIA	14.70	14.70	14.70
T. F	802.00	802.00	802.00
h. Btu/LB	1,434.82	1,434.82	1,434.82
TOTAL EXTRACTION. LB/HR	17,431.07	17,895.03	17,856.14
PART TO AIR EJECTOR	600.00	600.00	600.00
PART TO DEAERATOR	16,831.07	17,295.03	17,256.14
P. PSIA	71.00	71.00	71.00
T. F	400.00	400.00	400.00
h ISENTROPIC. BTU/LB	1,157.00	1,157.00	1,157.00
h. Btu/LB	1,219.32	1,219.32	1,219.32

EXTRACTION TO LP FWH, LB/HR	19,121.98	17,335.21	16,276.31
P, PSIA	18.00	18.00	18.00
T, F	230.00	230.00	230.00
h ISENTROPIC, BTU/LB	1,058.00	1,058.00	1,058.00
h, Btu/lb	1,140.12	1,140.12	1,140.12
CONDENSING FLOW, LB/HR	178,366.95	179,689.76	180,787.55
P, "HgA	2.00	2.50	3.00
T, F	101.14	108.70	115.00
h ISENTROPIC, BTU/LB	891.00	902.00	911.00
h, Btu/LB	989.19	998.32	1,005.79
POWER GENERATION, MW	27.60	27.18	26.84
GENERATOR EFFICIENCY, %	98.00%	98.00%	98.00%
TURBINE OUTPUT AT TERMINALS, kW	27,604.51	27,180.22	26,838.03
CONDENSER			
FLOW FROM CONDENSER, LB/HR	182,129.18	183,456.62	184,554.02
P, " HgA	2.00	2.50	3.00
T, F	101.14	108.70	115.00
h, Btu/LB	69.14	76.69	83.03
MAKE-UP TO CONDENSER, LB/HR	2,094.22	2,098.86	2,098.47
T, F	60.00	60.00	60.00
h, Btu/LB	28.06	28.06	28.06
CONDENSER DUTY, MM Btu/HR	164.16	165.63	166.82
EJECTOR CONDENSER			
P, PSIA	2.30	2.30	2.30
hf, Btu/LB	100.00	100.00	100.00
DUTY, Btu/HR	635,040.00	635,040.00	635,040.00
EJECTOR LOSS, LB/HR	12.00	12.00	12.00
FLOW TO CONDENSER, LB/HR	588.00	588.00	588.00
h, Btu/LB	1,180.00	1,180.00	1,180.00
ENTHALPY OF CONDENSATE, Btu/LB	72.63	80.15	86.47

GLAND STEAM CONDENSER			
P, PSIA	13.80	13.80	13.80
hf, Btu/LB	177.00	177.00	177.00
DUTY, BTU/HR	1,358,447.98	1,358,447.98	1,358,447.98
ENTHALPY OF CONDENSATE, Btu/LB	80.09	87.56	93.83
DEAERATOR			
FLOW FROM DEAERATOR, LB/HR	218,686.87	218,686.87	218,686.87
P, PSIA	61.20	61.20	61.20
T, F	294.00	294.00	294.00
h, Btu/LB	263.50	263.50	263.50
TEMPERATURE AFTER BOILER FEED PUMP, F	296.00	296.00	296.00
h, Btu/LB	265.60	265.60	265.60
LOSS FROM DEAERATOR VENT, LB/HR	168.31	172.95	172.56
h, Btu/LB	1,178.00	1,178.00	1,178.00
EXTRACTION FLOW, LB/HR	16,831.07	17,295.03	17,256.14
LP FEED WATER HEATER			
P, PSIA	17.00	17.00	17.00
hf, Btu/LB	187.66	187.66	187.66
STEAM FLOW REQUIRED, LB/HR	19,121.98	17,335.21	16,276.31
ENTHALPY INCREASE, BTU/LB	100.00	90.00	84.00
DUTY, Btu/HR	18,212,917.63	16,511,095.94	15,502,537.74
ENTHALPY OF CONDENSATE, Btu/LB	180.09	177.56	177.83
BOILER			
LOSS TO SOOT BLOWERS AND LEAKS, LB/HR	500.00	500.00	500.00
BLOWDOWN PERCENT OF FEED WATER, %	1.00%	1.00%	1.00%
BLOWDOWN, LB/HR	2,186.87	2,186.87	2,186.87
STEAM DRUM PRESSURE, PSIA	1,360.00	1,360.00	1,360.00

hg. Btu/LB	1,177.30	1,177.30	1,177.30
hf. Btu/LB	593.60	593.60	593.60
h. @ SH OUTLET. Btu/LB	1,468.60	1,468.60	1,468.60
BOILER DUTY. MM Btu/HR	261.02	261.02	261.02
HEATING VALUE OF BONE DRY WOOD. Btu/LB	8,500.00	8,500.00	8,500.00
MOISTURE CONTENT OF FUEL. %	47.00%	47.00%	47.00%
HEATING VALUE AS FIRED. Btu/LB	4,505.00	4,505.00	4,505.00
BOILER EFFICIENCY. %	70.00%	70.00%	70.00%
FUEL ENTERING BOILER. LB/HR	82,771.89	82,771.89	82,771.89
BLOWDOWN TANK			
P. PSIA	70.00	70.00	70.00
hf. Btu/LB	272.70	272.70	272.70
hg. Btu/LB	1,180.60	1,180.60	1,180.60
STEAM FLASHED TO DEAERATOR. LB/HR	772.96	772.96	772.96
BLOWDOWN TANK BOTTOMS TO DRAIN	1,413.91	1,413.91	1,413.91

COMBUSTION CALCULATION

INPUTS:

FUEL ULTIMATE ANALYSIS:

	DRY WEIGHT FRACTION
C	0.52
H2	0.063
N2	0.001
O2	0.405
S	0.001
ASH	0.01

FUEL DATA:

MOISTURE CONTENT: 47.00% 0.013 LB H2O/LB DRY AIR
FLOW RATE, LB/HR: 82772
PERCENT EXCESS O2: 20.00%

CALCULATIONS:

FUEL ANALYSIS:

	DRY WT%	A.F.WT%	LB/HR	MW	MOLES/HR
C	52.00%	27.56%	22811.96	12	1901.00
H2	6.30%	3.34%	2763.76	2	1381.88
N2	0.10%	0.05%	43.87	28	1.57
O2	40.50%	21.47%	17767.01	32	555.22
S	0.10%	0.05%	43.87	32	1.37
ASH	1.00%	0.53%	438.69		
H2O		47.00%	38902.84	18	2161.27
TOTAL	100.00%	100.00%	82772.00		

COMBUSTION AIR (O2) REQUIREMENT:

C+O2-->CO2 REQUIRES:	1901.00 MOLES O2
H2+1/2 O2-->H2O REQUIRES:	690.94 MOLES O2
S+O2-->SO2 REQUIRES:	1.37 MOLES O2
O2 REQUIRED FOR COMBUSTION (STOICH):	2593.31 MOLES O2
SUBTRACT O2 IN FUEL:	-555.22 MOLES O2
	2038.09 MOLES O2
ADD EXCESS O2:	407.62 MOLES O2
TOTAL O2 REQUIRED FROM COMBUSTION AIR:	2445.71 MOLES O2
COMBUSTION AIR REQUIRED:	11646.22 MOLES AIR/HR
=	335411.1 LB AIR/HR

FLUE GAS / COMBUSTION PRODUCTS

PRODUCTS	MW	MOLES/HR	LB/HR	VOL %	WT %
CO2	44	1901.00	83643.87	12.43%	19.79%
H2O	18	3785.39	68137.00	24.75%	16.12%
O2	32	407.62	13043.76	2.66%	3.09%
N2	28	9202.08	257658.20	60.15%	60.97%
SO2	64	1.37	87.74	0.01%	0.02%
TOTAL		15297.46	422570.56	100.00%	100.00%

FLUE GAS AT 350 F: 152605.8 ACFM

DRY FLUE GAS 354434 LB/HR
11512.06 MOLES/HR

MW DRY FLUE GAS 30.79 LB/MOLE

DENSITY OF AIR @ 60 F. 14.7 PSIA: 0.0763 LB/CU FT
DENSITY OF DRY FLUE GAS @ 60 F: 0.0811 LB/CU FT

VOLUME OF DRY FLUE GAS: 72849.4 SDCFM

DRY FLUE GAS / COMBUSTION PRODUCTS:

PRODUCTS	MW	MOLES/HR	LB/HR	VOL %	WT %
CO2	44	1901.00	83643.87	16.51%	23.60%
O2	32	407.62	13043.76	3.54%	3.68%
N2	28	9202.08	257658.20	79.93%	72.70%
SO2	64	1.37	87.74	0.01%	0.02%
TOTAL		11512.06	354433.57	100.00%	100.00%

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15-MW PLANT

STEAM CYCLE HEAT AND MASS BALANCE
EGLIN AFB BIOMASS ENERGY STUDY

SUMMARY:	DESIGN		
FUEL REQUIRED, TONS/HR	24.9	24.9	24.9
FUEL HEATING VALUE, BTU/LB (DRY)	8,500.00	8,500.00	8,500.00
MOISTURE CONTENT OF FUEL, % WB:	47.00%	47.00%	47.00%
BOILER DUTY, MM BTU/HR:	157.28	157.28	157.28
STEAM TURBINE BACK PRESSURE, " HgA	2.0	2.5	3.0
GROSS POWER OUTPUT, MW:	16.61	16.36	16.15
PARASITIC LOAD, MW	1.32	1.32	1.32
NET POWER OUTPUT, MW	15.29	15.04	14.83
STEAM TURBINE			
EXTRACTION EFFICIENCY, %	80.00%	80.00%	80.00%
CONDENSING EFFICIENCY, %	83.00%	83.00%	83.00%
THROTTLE FLOW, LB/HR	130,000.00	130,000.00	130,000.00
P, PSIA	1,250.00	1,250.00	1,250.00
T, F	950.00	950.00	950.00
h, Btu/LB	1,468.60	1,468.60	1,468.60
GLAND SEAL LEAK, LB/HR	650.00	650.00	650.00
P, PSIA	14.70	14.70	14.70
T, F	802.00	802.00	802.00
h, Btu/LB	1,434.82	1,434.82	1,434.82
TOTAL EXTRACTION, LB/HR	10,503.55	10,783.76	10,760.28
PART TO AIR EJECTOR	600.00	600.00	600.00
PART TO DEAERATOR	9,903.55	10,183.76	10,160.28
P, PSIA	71.00	71.00	71.00
T, F	400.00	400.00	400.00
h ISENTROPIC, BTU/LB	1,157.00	1,157.00	1,157.00
h, Btu/LB	1,219.32	1,219.32	1,219.32

EXTRACTION TO LP FWH. LB/HR	11,548.92	10,469.78	9,830.25
P. PSIA	18.00	18.00	18.00
T. F	230.00	230.00	230.00
h ISENTROPIC. BTU/LB	1,058.00	1,058.00	1,058.00
h. Btu/lb	1,140.12	1,140.12	1,140.12
CONDENSING FLOW. LB/HR	107,297.53	108,096.45	108,759.47
P. "HgA	2.00	2.50	3.00
T. F	101.14	108.70	115.00
h ISENTROPIC. BTU/LB	891.00	[illegible]	911.00
h. Btu/LB	989.19	998.32	1,005.79
POWER GENERATION. MW	16.61	16.36	16.15
GENERATOR EFFICIENCY. %	98.00%	98.00%	98.00%
TURBINE OUTPUT AT TERMINALS.kW	16,611.25	16,356.12	16,150.36
CONDENSER			
FLOW FROM CONDENSER. LB/HR	109,998.83	110,800.56	111,463.34
P. " HgA	2.00	2.50	3.00
T. F	101.14	108.70	115.00
h. Btu/LB	69.14	76.69	83.03
MAKE-UP TO CONDENSER. LB/HR	1,463.30	1,466.10	1,465.87
T. F	60.00	60.00	60.00
h. Btu/LB	28.06	28.06	28.06
CONDENSER DUTY, MM Btu/HR	98.75	99.63	100.35
EJECTOR CONDENSER			
P. PSIA	2.30	2.30	2.30
hf. Btu/LB	100.00	100.00	100.00
DUTY. Btu/HR	635,040.00	635,040.00	635,040.00
EJECTOR LOSS. LB/HR	12.00	12.00	12.00
FLOW TO CONDENSER. LB/HR	588.00	588.00	588.00
h. Btu/LB	1,180.00	1,180.00	1,180.00
ENTHALPY OF CONDENSATE. Btu/LB	74.91	82.42	88.73

GLAND STEAM CONDENSER			
P, PSIA	13.80	13.80	13.80
hf, Btu/LB	177.00	177.00	177.00
DUTY, BTU/HR	817,584.43	817,584.43	817,584.43
ENTHALPY OF CONDENSATE, Btu/LB	82.35	89.80	96.06
DEAERATOR			
FLOW FROM DEAERATOR, LB/HR	131,818.18	131,818.18	131,818.18
P, PSIA	61.20	61.20	61.20
T, F	294.00	294.00	294.00
h, Btu/LB	263.50	[illegible]	263.50
TEMPERATURE AFTER BOILER FEED PUMP, F	296.00	296.00	296.00
h, Btu/LB	265.60	265.60	265.60
LOSS FROM DEAERATOR VENT, LB/HR	99.04	101.84	101.60
h, Btu/LB	1,178.00	1,178.00	1,178.00
EXTRACTION FLOW, LB/HR	9,903.55	10,183.76	10,160.28
LP FEED WATER HEATER			
P, PSIA	17.00	17.00	17.00
hf, Btu/LB	187.66	187.66	187.66
STEAM FLOW REQUIRED, LB/HR	11,548.92	10,469.78	9,830.25
ENTHALPY INCREASE, BTU/LB	100.00	90.00	84.00
DUTY, Btu/HR	10,999,883.15	9,972,050.07	9,362,920.74
ENTHALPY OF CONDENSATE, Btu/LB	182.35	179.80	180.06
BOILER			
LOSS TO SOOT BLOWERS AND LEAKS, LB/HR	500.00	500.00	500.00
BLOWDOWN PERCENT OF FEED WATER, %	1.00%	1.00%	1.00%
BLOWDOWN, LB/HR	1,318.18	1,318.18	1,318.18
STEAM DRUM PRESSURE, PSIA	1,360.00	1,360.00	1,360.00

hg, Btu/LB	1,177.30	1,177.30	1,177.30
hf, Btu/LB	593.60	593.60	593.60
h, @ SH OUTLET, Btu/LB	1,468.60	1,468.60	1,468.60
BOILER DUTY, MM Btu/HR	157.28	157.28	157.28
HEATING VALUE OF BONE DRY WOOD, Btu/LB	8,5 .00	8,500.00	8,500.00
MOISTURE CONTENT OF FUEL, %	.00%	47.00%	47.00%
HEATING VALUE AS FIRED, Btu/LB	4,505.00	4,505.00	4,505.00
BOILER EFFICIENCY, %	70.00%	70.00%	70.00%
FUEL ENTERING BOILER, LB/HR	49,874.18	49,874.18	49,874.18
BLOWDOWN TANK			
P, PSIA	70.00	70.00	70.00
hf, Btu/LB	272.70	272.70	272.70
hg, Btu/LB	1,180.60	1,180.60	1,180.60
STEAM FLASHED TO DEAERATOR, LB/HR	465.92	465.92	465.92
BLOWDOWN TANK BOTTOMS TO DRAIN	852.27	852.27	852.27

COMBUSTION CALCULATION

INPUTS:

FUEL ULTIMATE ANALYSIS:

	DRY WEIGHT FRACTION
C	0.52
H2	0.063
N2	0.001
O2	0.405
S	0.001
ASH	0.01

FUEL DATA:

MOISTURE CONTENT: 47.00% 0.013 LB H2O/LB DRY AIR
FLOW RATE, LB/HR: 49874
PERCENT EXCESS O2: 20.00%

CALCULATIONS:

FUEL ANALYSIS:

	DRY WT%	A.F.WT%	LB/HR	MW	MOLES/HR
C	52.00%	27.56%	13745.27	12	1145.44
H2	6.30%	3.34%	1665.29	2	832.65
N2	0.10%	0.05%	26.43	28	0.94
O2	40.50%	21.47%	10705.45	32	334.55
S	0.10%	0.05%	26.43	32	0.83
ASH	1.00%	0.53%	264.33		
H2O		47.00%	23440.78	18	1302.27
TOTAL	100.00%	100.00%	49874.00		

COMBUSTION AIR (O2) REQUIREMENT:

C+O2-->CO2 REQUIRES:	1145.44 MOLES O2
H2+1/2 O2--> H2O REQUIRES:	416.32 MOLES O2
S+O2--> SO2 REQUIRES:	0.83 MOLES O2
O2 REQUIRED FOR COMBUSTION (STOICH):	1562.59 MOLES O2
SUBTRACT O2 IN FUEL:	-334.55 MOLES O2
	1228.04 MOLES O2
ADD EXCESS O2:	245.61 MOLES O2
TOTAL O2 REQUIRED FROM COMBUSTION AIR:	1473.65 MOLES O2
COMBUSTION AIR REQUIRED:	7017.39 MOLES AIR/HR
=	202100.8 LB AIR/HR

FLUE GAS / COMBUSTION PRODUCTS

PRODUCTS	MW	MOLES/HR	LB/HR	VOL %	WT %
CO2	44	1145.44	50399.34	12.43%	19.79%
H2O	18	2280.87	41055.73	24.75%	16.12%
O2	32	245.61	7859.48	2.66%	3.09%
N2	28	5544.68	155251.11	60.15%	60.97%
SO2	64	0.83	52.87	0.01%	0.02%
TOTAL		9217.430	254618.52	100.00%	100.00%

FLUE GAS AT 350 F: 91952.1 ACFM

DRY FLUE GAS 213563 LB/HR
6936.56 MOLES/HR

MW DRY FLUE GAS 30.79 LB/MOLE

DENSITY OF AIR @ 60 F, 14.7 PSIA: 0.0763 LB/CU FT
DENSITY OF DRY FLUE GAS @ 60 F: 0.0811 LB/CU FT

VOLUME OF DRY FLUE GAS: 43895.2 SDCFM

DRY FLUE GAS / COMBUSTION PRODUCTS:

PRODUCTS	MW	MOLES/HR	LB/HR	VOL %	WT %
CO2	44	1145.44	50399.34	16.51%	23.60%
O2	32	245.61	7859.48	3.54%	3.68%
N2	28	5544.68	155251.11	79.93%	72.70%
SO2	64	0.83	52.87	0.01%	0.02%
TOTAL		6936.56	213562.80	100.00%	100.00%

APPENDIX B

DRAWINGS AND DIAGRAMS

NOTE: Because these are blueprints, they are not specifically titled as figures.

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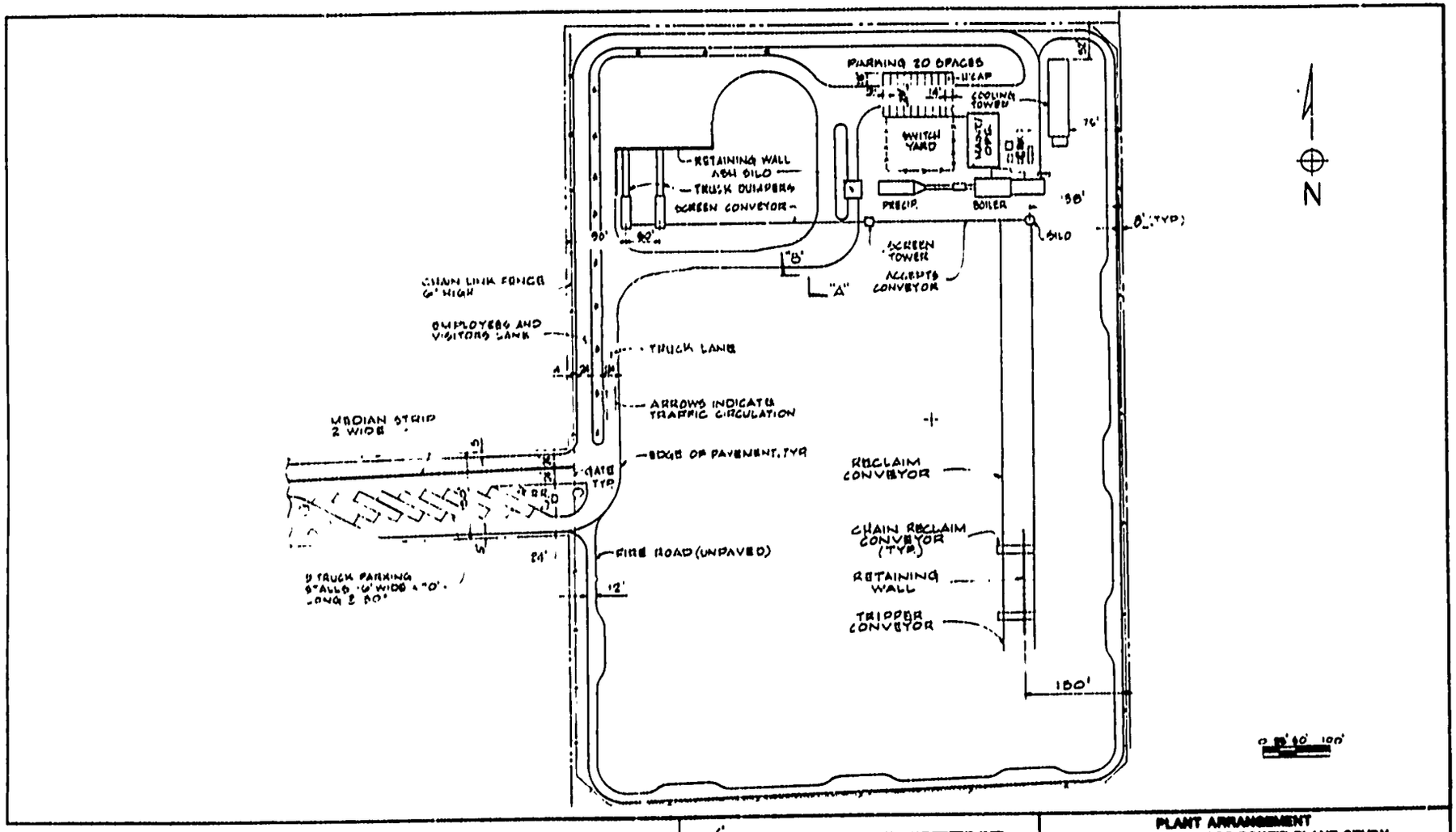

ULTRASYSTEMS ENGINEERS AND CONSTRUCTORS INCORPORATED	PLANT ARRANGEMENT EGLIN A.F.B. BIOMASS POWER PLANT STUDY EGLIN A.F.B. FLORIDA	
	PROJ. NO. 666	DRAWING NO C-666-001 REV.

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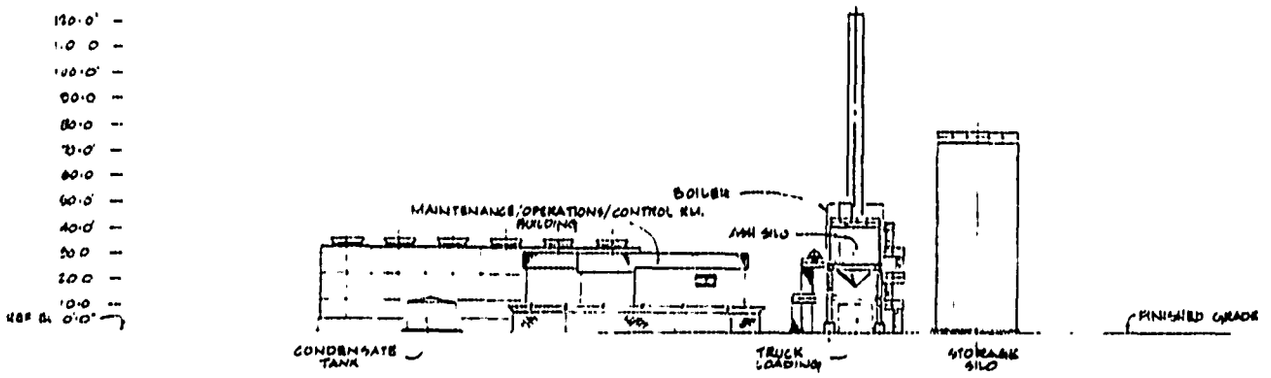

ULTRASYSTEMS ENGINEERS AND CONSTRUCTORS INCORPORATED	ELEVATIONS EGLIN A.F.B. BIOMASS POWER PLANT STUDY EGLIN A.F.B. FLORIDA
PROJ. NO. 666	DRAWING NO. C-666-002
REV.	

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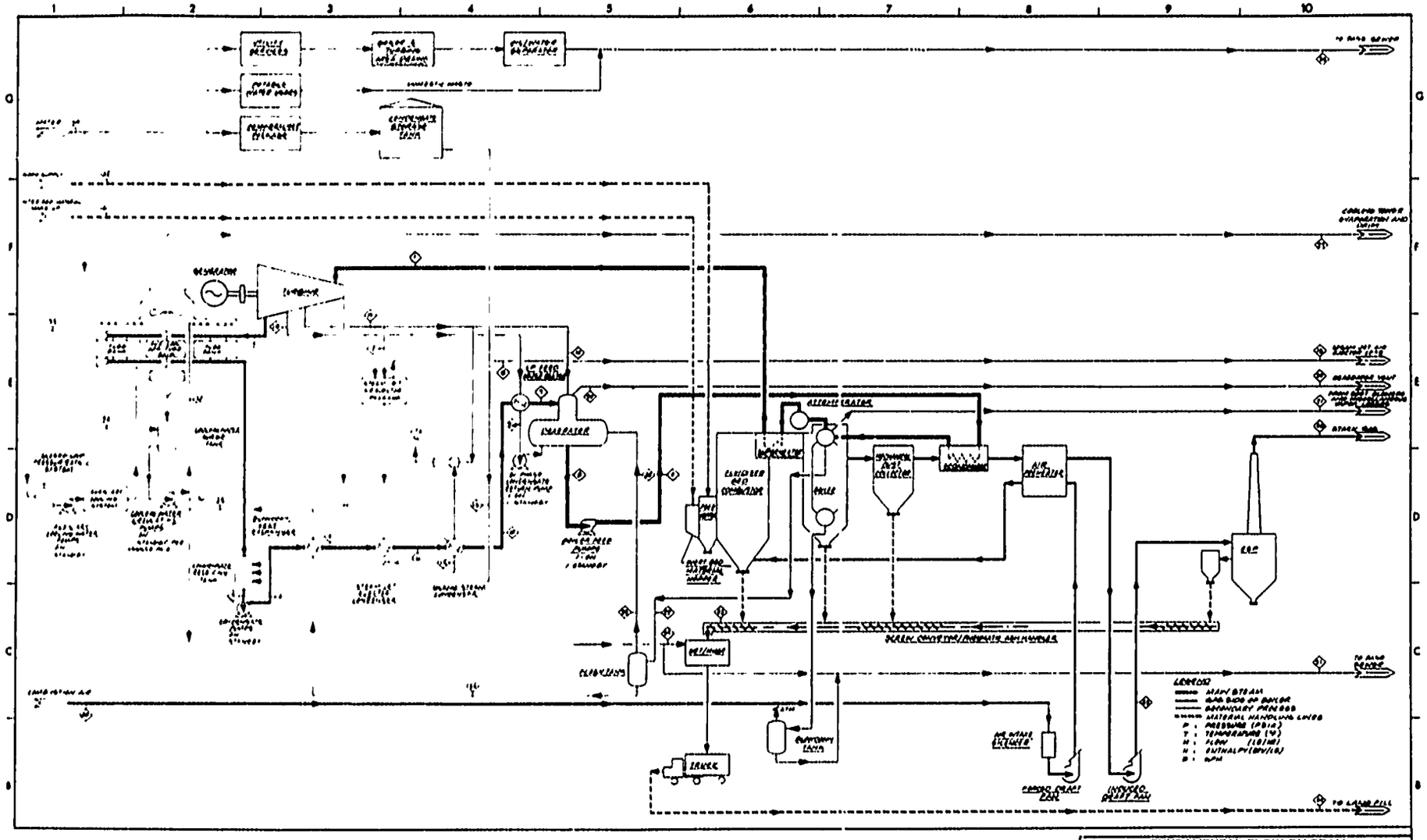

FUNDAMENTAL FLOW DIAGRAM
EGLIN A.F.B. BIOMASS POWER PLANT STUDY

EGLIN A F B., FLORIDA

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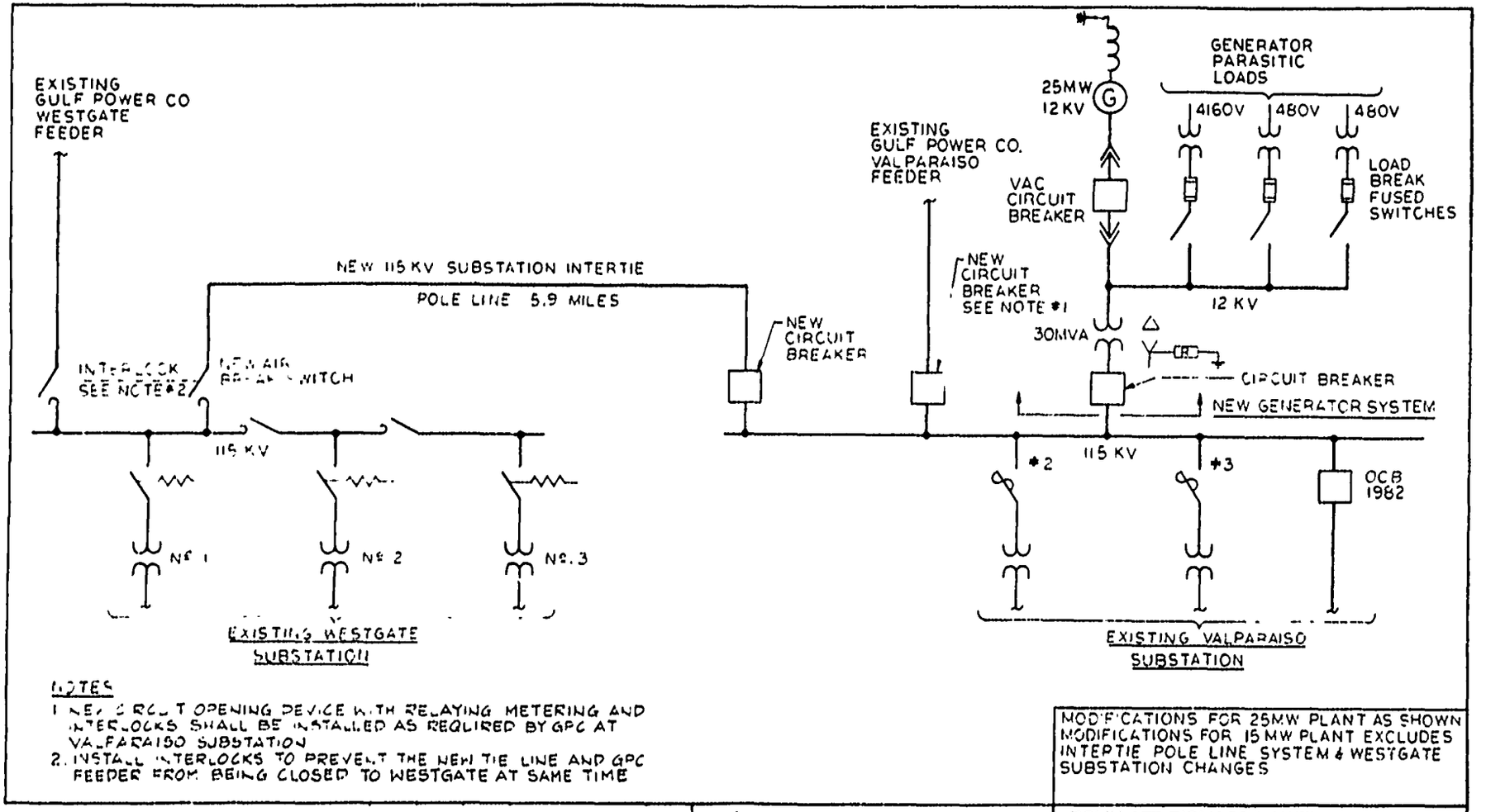

NOTES

1. NEW CIRCUIT OPENING DEVICE WITH RELAYING METERING AND INTERLOCKS SHALL BE INSTALLED AS REQUIRED BY GPC AT VALPARAISO SUBSTATION
2. INSTALL INTERLOCKS TO PREVENT THE NEW TIE LINE AND GPC FEEDER FROM BEING CLOSED TO WESTGATE AT SAME TIME

MODIFICATIONS FOR 25MW PLANT AS SHOWN
MODIFICATIONS FOR 15 MW PLANT EXCLUDES INTERTIE POLE LINE SYSTEM & WESTGATE SUBSTATION CHANGES

ULTRASYSTEMS
ENGINEERS AND CONSTRUCTORS
INCORPORATED

EGLIN AFB BIOMASS POWER PLANT STUDY
SINGLE LINE DIAGRAM

PROJ. NO.	DRAWING NO	REV
898	898-06-101	0

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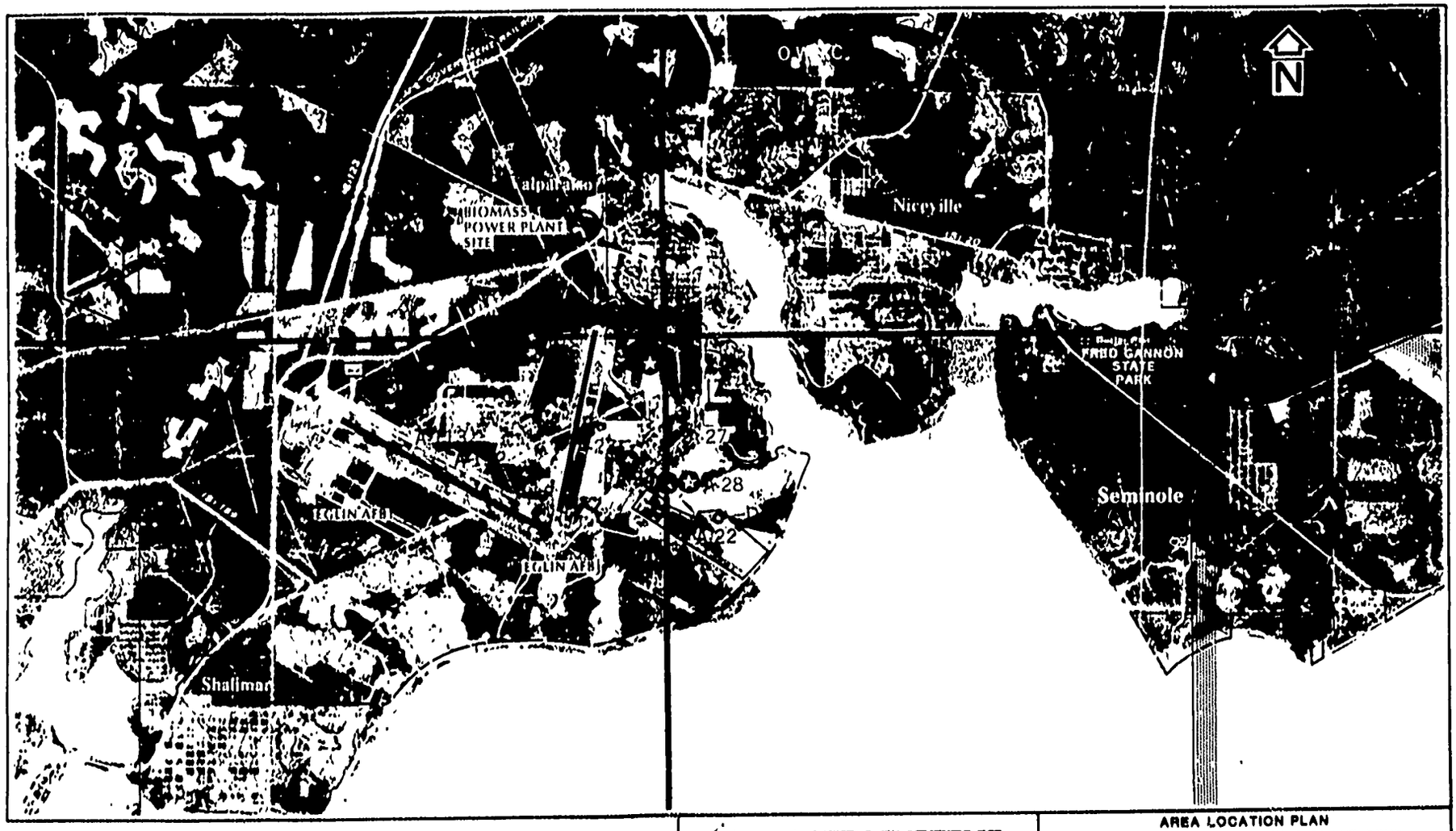

ULTRASYSTEMS
ENGINEERS AND CONSTRUCTORS
INCORPORATED

AREA LOCATION PLAN
EGLIN A.F.B. BIOMASS POWER PLANT STUDY
EGLIN A.F.B. FLORIDA

PROJ. NO.	DRAWING NO	REV
898	T-898-100	

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APPENDIX C

DETAILED DESIGN DESCRIPTION

A. DETAILED DESIGN DESCRIPTIONS

1. Site Development

a. Clearing, Grading, and Landscaping

Clearing will be limited to the necessary removal vegetation to make way for structures, parking areas, access roads, and the wood fuel storage pile, including the cleared areas around the wood pile required by the Eglin Air Force Base Engineer.

In general, grading will be limited to only that necessary for constructing flat-pads for structures, parking areas, roadways, the wood storage area, and site drainage.

b. Fencing

Chainlink fencing will be furnished around the perimeter of the plant and woodyard. Gates will be furnished at appropriate locations to be determined during detailed design.

c. Roads

The roads, hardstands, and truck turnaround in the wood fuel receiving area will be designed to accommodate 70-foot, tractor-trailer trucks at a maximum gross weight of 60 tons.

A gravel road will be provided around the perimeter of the woodyard area to accommodate firefighting equipment.

2. Foundations

Foundations will be designed to bear on undisturbed earth, or engineered fill. Foundations for buildings and structures will be the spread footing type, and the turbine generator is to be set on a mat on-grade foundation.

Piles are not included in the scope of the project.

Should the geotechnical investigation show that another type of foundation is necessary, or that an anomaly exists, the scope will be redefined, and the budget cost adjusted accordingly.

3. Structural Steel

a. Design Criteria

Structural design will be performed in accordance with accepted practice, applicable codes and standards, including the local building code (Uniform Building Codes (UBC), where local code does not apply). Wind loads, and seismic zone consideration for the locale will be included in the design.

b. Woodyard Structures

Woodyard structures will be purchased equipment. Vendors' drawings and literature will be reviewed to ascertain the structural integrity of their equipment.

Structural steel furnished with equipment will be painted.

c. Applicable Specifications

In general, structural steel will be designed for Type 2 construction (AISC specification).

4. Buildings

a. Design Criteria

Buildings required for weather and personnel protection will be preengineered, steel-framed, insulated, and with metal siding.

Civil design will be performed in accordance with accepted good practice, applicable codes, and standards including the local building code (Uniform Building Code, where local code does not apply). Wind loads, and seismic zone consideration for the locale would be included in the design.

b. Building(s)

A building will be required for maintenance, personnel, control, and switchgear. The personnel facility will include offices, men's and women's toilets, change facilities, and a combination lunch and training room.

A roll-up door will provide equipment access.

Enclosures for the boiler and turbine areas are not provided.

5. Underground Piping

a. Design Criteria

The selection of piping materials will be based on mechanical properties, as well as plant site economics.

b. Codes and Standards

Water and Sewage Systems: Uniform Plumbing Code (UPC)
Firemain System: National Fire Protection Association Code (NFPA)

6. Electrical Systems

a. System Analysis

The proposed system additions and modifications will be discussed in detail with the base civil engineer.

The present systems and anticipated future needs and expansions will be thoroughly scrutinized, and new facilities caused to dovetail with those conditions.

All anticipated changes will be coordinated with the local utility. Particular attention will be given to protection interlocks with the utility feeders, as well as changes required within the utility system.

Fault current and load flow studies will be made to ascertain if existing facilities are suitable for the proposed additional power.

b. Proposed New Facilities

Electrical systems will be provided for the new biomass generating plant.

Modifications will be made at the Eglin AFB Valparaiso substation to accept power from the new plant, and to coordinate it with the Gulf Power Company's utility feeder.

In the case of the 25-MW_e plant, an intertie pole line will be constructed to connect the Eglin AFB Valparaiso and Westgate substations.

c. Generating Plant

Power will be generated at a nominal 12-kV, and delivered through a step-up transformer to the Valparaiso utility substation 115-kV bus.

Power for the plant parasitic loads will be taken from the plant 12-kV system on the substation side of the generator breaker. A unit substation will provide power at 4,160-Volts for the large fans and boiler feed pumps; one or more unit substations will provide power at 480-Volts for the balance of plant loads.

The generator neutral will be grounded through a distribution transformer.

The generator power system will include a vacuum breaker and the following protective relay systems:

- Phase Overcurrent
- Reverse Power
- Phase Current Unbalance and Negative Sequence
- Loss of Excitation
- Phase and Ground Differential
- Out of Step
- Neutral Overcurrent
- Field Ground

Metering will be provided to monitor generator and plant current, voltage, frequency power factor, power, and energy.

Manual and automatic synchronizing systems will be provided to synchronize the generator to the 12-kV system at the generator breaker.

The step-up transformer will be a two-winding unit. Winding connections will be coordinated with the local utility to assure system and protection compatibility. The transformer will be provided with the following protection, alarm, and indication systems:

- Phase Differential
- Neutral Overcurrent
- Sudden Pressure
- Low Oil Level
- Oil and Winding Temperature
- Pressure/Vacuum

Lightning/surge arrestors will be provided at the generator and step-up transformer.

d. Valparaiso Substation

A suitable circuit breaker or circuit interrupting device will be installed to connect the generator system to the 115 kV substation bus. Interlocks will be provided to prevent closing a live generating system to a live bus system.

Circuit control equipment, as required by the local utility will be installed in the utility feeder to the substation at the substation.

A suitable circuit breaker or interrupting device will be installed to serve the substation intertie line.

Insofar as practicable, the existing substation distribution facilities will not be disturbed.

e. Substation Intertie Line

A 115 kV pole line will be installed to connect the Eglin AFB Valpariso and Westgate Substations.

The line will be sized to carry the total Westgate substation load.

An air-break switch will be installed at the Westgate substation to connect the tie line to the substation bus. This switch will be mechanically interlocked with the utility feeder switch so as to prevent the tie line and utility feeder from simultaneously energizing the substation bus.

Insofar as practicable, the existing substation distribution facilities will not be disturbed.

7. Instrumentation and Control

a. System Function

The function of the instrumentation and control system is to indicate and control the various processes within the facility. In addition, the control room instrumentation will provide the operator with a window on the plant, and will act as the nerve center.

b. System Design Criteria

The instruments and control systems proposed for this project will be of proven reliability in similar facilities, and be of a manufacturers standard design and manufacture. The central control room concept will be used. The system furnished will be an analog or a microprocessor-based type, either centralized or distributed. The instrumentation, such as transmitters, will be solid state type and utilize the industry standard 4-20 milliamp direct current signal. Actuators will be pneumatic-powered and controlled through current to pneumatic transducers. Critical control loops will have control backup.

c. Combustion Control

The combustion control will make use of a two element master pressure control system. The two elements will be steam flow as feedforward, and steam pressure as trim. Variations in steam pressure will cause the fuel

and air quantity to change in an operator-adjustable ratio. The system will also incorporate a lead-lag circuit such that on a load increase, air leads the fuel and on a load decrease, the fuel leads the air, and will include O_2 correction.

d. Drum Level Control

The drum level control will be of the three-element type utilizing temperature compensated steam flow, feedwater flow, and drum level.

e. Steam Temperature Control

The final steam temperature control will be of the two-element type, employing superheater interstage temperature, cascaded to the measurement of main or final steam temperature.

f. Deaerator Pressure Control

Deaerator pressure will be maintained within the specified limits utilizing a steam pressure reducing valve.

g. Deaerator Level Control

The deaerator level control system will be of the three-element design using feedwater flow, condensate flow, and deaerator level.

h. Hotwell Level Control

The hotwell level control will be accomplished from the control system. The hotwell water level controller will continuously detect condensate level, and automatically control the water level in the hotwell.

i. Auxiliary Steam Pressure Control

Auxiliary steam pressure will be controlled using a standard pneumatic or electronic valve-mounted pressure controller.

j. Air Quality Monitoring

The stack effluent will be monitored for opacity. The analyzer system will be certified by the vendor to meet EPA and local requirements.

k. Miscellaneous Instrumentation

Critical plant parameters will be monitored and alarmed, such as:

Turbine bearing temperature.
Generator winding temperature.
Boiler feed pump bearing temperature.
Boiler draft pressure.
Dust collector differential pressure.
Particle collector differential pressure.
Plant condensate return contamination.
Turbine vibration.
Induced-draft fan vibration.
Forced-draft fan vibration.
Boiler feed pump protection system.

l. Boiler Feed Pumps

Each boiler feed pump will be equipped with minimum flow recirculation controls. In addition, the net positive suction head (NPSH) will be calculated within the central control system. Upon detection of a low NPSH, the operator will be alerted via an alarm.

8. Steam Piping System

a. System Function

The steam system provides the required steam from the steam generator to the main steam turbine, air ejectors, and the main turbine steam seals.

b. System Design Criteria

Maximum Design Capacity	216,000 lb/hr
Maximum Operating Pressure	1,265 psia
Maximum Operating Temperature	955°F

The main steam piping will be installed in accordance with the ANSI Power Piping Code. Valves and fittings will have an ANSI pressure rating which is appropriate for the design pressure and temperature conditions.

c. Applicable Codes and Standards

ANSI B31.1 Power Piping
ASME Boiler and Pressure Vessel Code
Heat and Material Balance

d. System Description

(1) Main Steam Piping

The main steam system includes the piping from the boiler block valve outlet to the turbine generator unit complete with accessories, steam seal piping and drains.

The steam piping installation will make use of changes of direction and expansion loops to absorb thermal stresses. Insulation will be provided. The piping will be sloped for drainage with drip legs located in appropriate locations. Relief valves will be located at the outlet of pressure reducing valves, to protect the downstream piping.

A steam attemperator will be used to control boiler outlet steam temperature. The attemperator will be a mechanically atomizing "desuperheater," utilizing boiler feedwater as the spray medium.

(2) Turbine Generator

The turbine will be a condensing unit with an uncontrolled extractions complete with main stop valve, gland steam sealing system, complete lube oil and control oil system, turbine control panel, emergency overspeed system, governor control and protective system, turbine supervisory system and protective trips.

Alarms will be furnished to alarm conditions that could affect safe turbine operations (such as high vibration).

(2) Extraction Steam

The (uncontrolled) extraction steam systems will provide for the steam supply to the deaerator, the low pressure feedwater heater, and the gland seal system.

A reverse flow valve will be located in the extraction outlets from the turbine generator to prevent overspeed in the event of a turbine trip. Isolation valves in the branch line from the extraction header will be manually operated. A pressure control valve with manual bypass will be located in the supply line to the deaerator.

9. Condensate System

a. System Function

The function of this system is to condense the steam from the turbine generator, and to transfer the condensate to the deaerator for removal of dissolved oxygen, and reuse as boiler feedwater.

The condensate system includes the main steam condenser, gland steam condenser, ejector condensers, condensate pumps, deaerator, LP feedwater heater, condensate tank, and interconnecting piping and valves.

b. Applicable Codes

ANSI	B 31.1 Power Piping
ASME	Boiler and Pressure Vessel Code
HEI	Heat Exchanger Institute Heat and Material Balance

c. System Description

(1) Condenser

The main condenser will be a wet surface, air-cooled condenser. Cooling water is circulated over the condenser tubes to absorb the heat, which is subsequently rejected to the mechanically induced air flow and hence, to the atmosphere.

The condenser will be brought under a vacuum by the hogging ejector prior to startup of the turbine. After initial startup, operation of the condensate system will be essentially automatic. The hotwell level will be maintained automatically, as will be the deaerator storage tank level.

During operation, vacuum will be maintained by the condensing of exhaust steam, and by operation of the air ejector package. Condensate level in the condenser hotwell will be maintained by a level controller.

The condenser hotwell will provide suction head for the condensate pumps, and will be the receiving point for various piping and equipment drains. The drains which will be routed to the condenser will only be those which provide high-quality condensate.

(2) Steam Jet Air Ejectors

The steam jet air ejector package will use ejectors (eductors) to remove noncondensible gases from the condenser. Operation will be strictly manual. Steam from the auxiliary steam system (pressure reduced steam from the steam drum) will be the motive fluid.

(3) Gland Steam Condenser

The gland steam condenser will be a shell and tube type which will use condensate for cooling the gland exhaust steam.

(4) Condensate Pumps

Two 100-percent capacity, electric motor-driven condensate pumps will be provided. Under normal operating conditions, one of the 100-percent condensate pumps will be in operation, while the second pump will be on standby.

The pumps will be started manually, either locally or from the control room, the only permissive being that the condenser hotwell level is not LO-LO.

A minimum recirculation control valve will ensure adequate flow through the pumps to prevent their overheating, and will provide a minimum flow through the gland steam condenser and steam jet air ejector condenser.

(5) Condensate Storage Tank

Makeup to the condenser will be provided by a gravity flow line from the condensate storage tank. The tank will be elevated sufficiently, and the line sized adequately to meet the maximum makeup required under any circumstances. This would include a turbine trip when the condenser vacuum had been broken, and steam vented to atmosphere. The condensate storage tank will be sized to allow 2 days of plant operation without being replenished by the demineralized water system.

10. Feedwater System

a. System Function

The function of the boiler feedwater system will be to provide feedwater to the steam generator at the appropriate pressure and temperature. The boiler feed system will include two 100-percent capacity feed pumps, and associated valves and piping.

b. System Design Criteria

Sizing of the feed pumps will be in accordance with ASME Code, with margin added for transient operating conditions. The design flow rate will be based upon boiler steam output rate and feedwater flow rate.

c. Applicable Codes

ASME Boiler and Pressure Vessel Code
ANSI B31.1 Power Piping

d. System Description

(1) Deaerator

The deaerator will be a direct contact feedwater heater, and protected from overpressure by relief valves.

There will be four normal flows into the deaerator:

- Condensate/makeup from the hotwell - This is controlled by the deaerator level control valve.

- Steam supply to the deaerator - The normal steam flow to the deaerator is the turbine second extraction flow. This is an uncontrolled flow at a controlled pressure.

- Flash tank steam - Steam flashing in the flash tank is piped to the deaerator. This flow is uncontrolled.

- Low pressure feedwater heater condensate return.

There will be one intermittent flow into the deareator: this will be the boiler feed pump minimum recirculating flow.

There will be two normal flows out of the deareator:

- The deaerator steam/air vent - This will be uncontrolled, except by manual valve. A restriction orifice will be located downstream of the valve to limit the venting of steam.

- The feedwater flow to the boiler feedpumps - This flow will be controlled by the feedwater pump controls.

There would be one upset condition flow out of the deareator: this would be the deaerator HI level dump flow which will be controlled by a float and thermostatic trap.

(2) Boiler Feed System

The boiler feedwater system will operate automatically after initial startup. During normal operation, the boiler drum level will be maintained by a control valve on the pump discharge header. Minimum recirculation of the feedpump flow back to the deaerator will be controlled automatically by means of a recirculation system.

Two 100-percent multistage, horizontal centrifugal pumps will be provided. Both pumps are electrically driven.

The feedwater pumps will be be manually started or stopped either locally or from the control room. The feedwater pumps will be automatically tripped on high vibration, high temperature, low deaerator level, and low NPSH. Minimum flow will be maintained by means of a minimum recirculation control valve on the discharge of each pump. Flow to the drum will be controlled by a level control valve.

During automatic operation, a feedwater flow control valve will use "three-element" drum level controls to regulate feedwater flow: steam flow, feedwater flow, and drum level. During manual operation, the valve will be regulated by the plant operator.

11. Blowdown System

a. System Function

The function of the blowdown system will be to accept drain flows from various plant systems. The system will include a flash tank, an atmospheric blowdown tank, vent, and drain piping.

b. Applicable Codes

ASME Boiler and Pressure Vessel Code
ANSI B31.1 - Power Piping Code

c. System Description

A flash tank will be provided for continuous blowdown. A blowdown tank will be provided for intermittent and startup. This tank will receive flow from the boiler drum and steam line drains which are normally opened during startup.

During normal operation, the flash tank will receive continuous flow from the boiler drum.

Level will be maintained in the flash tank, and blowdown tank by a level controller.

12. Circulating Water System

a. System Function

The circulating water system supplies cooling water to meet the cooling requirements of the main steam condenser and the power plant auxiliary cooling system.

b. System Design Criteria

Design Wet Bulb Temperature 77°F

c. Applicable Codes

ASME Boiler and Pressure Vessel Code
ANSI B31.1 Power Piping Code

d. System Description

The circulating water system will supply cooling water to meet the cooling requirements of the condenser and the power plant auxiliary cooling system. The circulating water chemical feed system will inject biocide into the cooling water system for prevention of biological fouling, and sulphuric acid into the cooling water for pH control.

The condensing system will be a mechanical draft, wet surface, air-cooled condenser. The number of fans in operation will be sequentially controlled as required.

A float-operated level control valve will maintain the wet surface condenser circulating water receiving tank level.

The circulating water blowdown will be accomplished by sensing conductivity. Discharge will be routed to the base sewer system.

Two 100-percent capacity electric motor-driven circulating water pumps will be provided. One pump will normally be in operation while the other is on standby.

The discharge of each pump will be equipped with a motor operated butterfly valve.

13. Service Water System

a. System Function

The function of this system will be to provide water distribution for process, fire, potable, and service water uses in the plant.

b. Applicable Codes

Uniform Plumbing Code

c. System Description

The system will consist of a line from the Eglin AFB water system, and will supply water to the fire protection system, condenser system makeup, demineralizer, domestic water and utility service in the plant.

A raw water storage tank will not be included.

14. Closed Cooling Water System

a. System Function

The closed cooling water system (plant auxiliary cooling system) removes heat from the boiler feed pump bearing coolers, the sample coolers, turbine lube oil cooler, and the generator air/water cooler, and then rejects this heat by means of a dedicated heat transfer section in the wet surface, air-cooled condenser.

b. Applicable Codes

ANSI Power Piping Code, B31.1

c. System Description

Water will be supplied from the auxiliary cooling system circulating water pump discharge. The water will be supplied to the various heat exchangers arranged in parallel, back to the dedicated heat transfer section in the wet surface, air-cooled condenser. If required, cooling water flow through the various heat exchangers will be controlled by temperature controllers.

15. Station Air and Instrument Air System

a. Air System Function

The compressed air system will be provided for the distribution of clean, dry, oil-free instrument air to the various plant instrumentation and control devices. A separate service air distribution system will be provided.

b. System Description

Compressed air will be provided by two 100-percent electric motor-driven air compressors. An ASME standard receiver will be provided with 2-minute storage capacity. Two 100-percent filters and dryers will be provided to ensure proper air quality for the instrument air service. Service air outlets will be provided.

The total air flow requirement will be provided at approximately 100 psia, and the distribution piping will be sized accordingly.

The header will be maintained at constant pressure by the compressors. Air flow will be taken from the system as required for operation. Manual vent/drains will be provided in each main header.

16. Turbine Lube-Oil and Lube-Oil Purification System

a. System Function

This system will provide for the lubrication requirements of the steam turbine and turbine generator, the control oil supply and the purification of both the lubricant and control oil.

b. System Description

The turbine generator lube- and control-oil system will include three independent oil pumps that will ensure that the bearings receive sufficient lubricating oil in operating and upset conditions.

A high capacity, main oil pump, driven by an AC motor, will supply oil for lubrication and control while the turbine generator is running.

An auxiliary oil pump will supply lubricating oil while the set is being started up or is running down.

An emergency oil pump, driven by a DC motor, will be a centrifugal pump. In the event of loss of AC power, it will ensure that while the turbine generator is running down, sufficient oil is being supplied to the bearings.

17. Steam Generator System

a. System Function

The purpose of the steam generator will be to produce steam at the proper pressure, temperature, and flow to satisfy the steam requirements of the turbine generator.

b. System Design Criteria

Steam Generator

Design Capacity	216,000 lb/hr
Design Outlet Pressure	1,265 psia
Design Outlet Temperature	955°F

The design dry basis for the fuel is as fcllows:

Btu/lb (HHV)	8,500
Carbon %	52.0
Hydrogen %	6.3
Nitrogen %	0.1
Sulfur %	0.01
Ash %	1.0
Oxygen %	40.5

As delivered fuel assumed at 47-percent moisture content on wet basis.

c. Applicable Codes, Standards, and Specifications

ANSI B31.1 Power Piping
ASME Boiler and Pressure Vessel Code

d. System Description

The steam generator will be a fluidized-bed combustor design, and will be furnished complete with an economizer, superheater, and steam attemporator system.

The steam generator will include conveyor for combustor fuel feed, combustor blower, tramp iron removal, bed medium recirculation system, inert bed material hopper, and fuel feed metering bin. Also furnished will be integral valves and piping, including boiler safety valves, a main steam stop valve, feedwater inlet stop check valves, and blowdown and drain valves.

The steam generator will be designed to operate automatically to maintain the desired outlet steam conditions. The firing rate will be controlled by the combustion control system, and the drum level maintained by a feedwater control system.

(1) Air and Flue Gas

The air and flue gas system will provide combustion air to the furnace and remove the products of combustion from the furnace. The system will include the forced draft (FD) fan, the induced draft (ID) fan, and interconnecting ductwork.

The air and flue gas system will operate automatically. Air flow will be regulated by adjusting the FD fan damper. This will be controlled by the combustion control system. The ID fan damper will be automatically controlled to maintain furnace draft.

(2) Air Quality Control

The air quality control system will remove particulate from the dust-laden boiler gases to reduce stack emissions to acceptable local air quality standards.

The boiler manufacturer will supply a mechanical dust collector, which will remove a substantial portion of the larger particulate matter entrained in the flue gas stream. The mechanical dust collector will be a multiple cyclone-type. Fine particulate removal will be accomplished by an electrostatic precipitator (ESP) or baghouse as required. The ESP will limit the outlet particulate emissions to 0.01 gsdf.

The stack provided will be of sufficient diameter and height to ensure proper dispersion and draft. Stack gas emission monitoring will consist of an opacity meter located in the stack.

18. Fuel Handling System

a. System Function

The wood handling system provides a means of receiving, classifying, shredding, storing, reclaiming and transporting hogged woodwaste to the boiler feed hopper.

b. System Design Criteria

The system will be designed to handle wood fuel with the following fuel characteristics:

Acceptable Moisture Range	0-60-Percent
Average Moisture Content	47-Percent
Acceptable Particle Size to Boiler	3-inch minus
Average Bulk Density	20 lb/ft^3
Maximum Acceptable Length of Pieces to Unloader	2 ft

c. System Description

The wood handling system will be designed to receive, size, and transport woodwaste fuel to storage at a rate of 250 tph. The reclaimer system will feed fuel to the surge bin at rates up to 100 tph. The feed system will provide properly sized wood fuel to the boiler to maintain the design fuel-firing rate.

Wood fuel will be trucked to either one of two truck dumpers, each with a scale and receiving hopper. The reclaim from the hopper will be to a belt conveyor which will pass the fuel below a magnet, for tramp iron removal, and onto a disc screen. The disc screen will allow properly-sized material to be transferred directly to the transfer belt conveyor. Oversized material will be fed to a hog for size reduction and then be deposited on the transfer conveyor. The transfer conveyor delivers material to stackout conveyor and the storage pile. Front-end loaders supplied by Owner, will be used to spread fuel out onto the storage pile, and to move it back onto the reclaim system.

Wood fuel will be reclaimed by the use of underpile reclaimers. Reclaimed fuel from storage will be delivered to a surge bin equipped with feeders for handling fuel to the boiler.

(1) Wood Receiving and Unloading

Wood waste will normally be delivered to the site by truck, on a 5 day per week, 8 hour per day basis. Each truck will have a capacity of about 25 tons. During the delivery period, wood fuel will be transferred to the storage pile and to the boiler as required.

(2) Scales

A truck scale, which will be an integral part of each dumper, will consist of the necessary instrumentation to provide pertinent data required relative to custody transfer of wood fuel, such as before and after weights, net weights, and accumulation net weights.

(3) Truck Dumper and Hopper

The plant will be equipped with dual lifting platforms. The platforms will have A-frame type mounts with hydraulic cylinders for dumping into the receiving hopper.

(4) Magnet

An electromagnet will be used and will be so designed as to remove tramp iron from the fuel before it reaches the disc screen classifier and shredder. The magnet will be suspended above the belt conveyor discharge spout, delivering fuel to the screen. For cleaning, the magnet will be manually moved away from the conveyor, power removed, and accumulated tramp iron is collected in a bin at grade level.

(5) Classifying Station

The classifying station will consist of a disc screen and a wood and shredder. Wood fuel which matches specified dimensions will pass the screen and will be deposited onto the transfer conveyor. Oversized material passing over the screen will enter the hog where it will be reduced to specified size and deposited onto the transfer conveyor.

(6) Transfer Conveyor

The transfer conveyor will receive material from the classifying station and transfer it to the stackout conveyor and then to the storage pile. There will be a discharge point over each of two underpile reclaimers.

(7) Main Storage Pile

The main fuel storage pile will have space to contain approximately 3 months of supply at the maximum burn rate of the boiler.

(8) Fuel Feed System

The fuel feed system will consist of a mobile wheeled, front-end chip loader moving fuel from the plant storage pile to either one of two underpile reclaimers delivering fuel through a reclaim belt conveyor to the boiler surge bin.

(9) Reclaimer

The under pile reclaimer will automatically reclaim fuel as long as fuel is piled above it. It will move the wood fuel from the pile to the reclaimer outfeed conveyor. The chip loader, in working the pile, will keep fuel piled above the reclaimer.

(10) Reclaimer Outfeed Conveyor

This conveyor will move chips from the reclaimer and deliver them to the surge bin. The conveyor will be designed to carry a maximum of approximately 100 tons per hour.

(11) Surge Bin

The surge bin will provide a minimum of a 3-hour supply of fuel near the boiler.

19. Ash Handling System

a. System Function

This system will cover the removal of ash from the steam generator system and air quality control system, and from there to a loading system for disposal in a landfill.

b. System Description

One complete ash collection and removal system designed to handle approximately 30 tons per day of boiler and fly ash will be furnished. This will accommodate ash produced from normal plant operation. The removal system will operate semiautomatically once it is manually started by the plant operator. The ash will be moved to an ash container where it will be hauled away by truck.

20. Heating Ventilating and Air-Conditioning System

a. System Function

The function of the HVAC system will be to maintain building indoor air temperature and humidity within specified limits.

b. System Design Criteria

The control room HVAC system will be designed to maintain the temperature at 73°±5°F and the relative humidity between 10 and 50 percent. The room will be kept at a positive pressure with respect to the surrounding space. The air will be filtered.

c. System Description

A heating, ventilating, and air-conditioning system will be furnished for the control room and adjacent offices. Heating and ventilation will be provided in the maintenance area.

The HVAC system will be controlled automatically by a control station located within the control room.

21. Plumbing System (Drainage and Potable Water)

a. Plumbing-Drainage System Function

This system will provide the drainage management of storm water, utility water and sanitary water.

b. Drainage System Design Criteria

Applicable Codes

WPCF Manual of Practice No. 9
Titled: "Design and Construction of Sanitary and Storm Sewers"
Uniform Plumbing Code (this code is applicable, if a local plumbing code does not exist).
Standards & Guides: Applicable Ultrasystems Standards & Guides

c. Drainage System Description

(1) Storm Drains

Storm drainage will be accomplished by extending the existing base drainage system as required, and if applicable.

(2) Utility Services

Utility water used for general housekeeping, boiler area and maintenance area floor drains will be collected and will be routed via an oil/water separator to the sewer.

(3) Sanitary Drains

Sanitary sewer drain points will be collected by a dedicated system and routed to the sewer.

d. Potable Water System Design Criteria

The potable water system will provide for the supply and distribution of domestic quality water to users throughout the plant.

The potable water piping will be installed in accordance with the ANSI code, and valves and fittings will have an ANSI pressure rating and material suitable for the intended service. High point vents and low point drains will be provided.

e. Potable Water System Description

Water supply for the diverse plant users will be obtained from the Eglin AFB water system directly into the system which will service all domestic water users such as drinking fountains, washrooms and the chemical lab.

22. Fire Protection System

a. System Function

All underground piping in the fire protection system will be PVC Class 150 AWWA C-900, Cast Iron O.D., with elastomeric couplings, subject to final check of local requirements.

b. Applicable Codes

All underground piping and above ground piping shall conform to NFPA Codes and applicable local codes.

c. System Description

A central fire alarm control panel will be located in the control room. The water required for the fire protection system will be supplied from the local water system, or base fire protection system, as applicable.

Fire protection water will be routed underground to a piping loop system which covers those areas in the plant that are protected by fire hydrants. The fire protection system will service the following areas:

Area	Type of Protection
Woodyard Area	Hydrants and portable extinguishers at truck dumper and conveyor areas. Ring of hydrants and post indicator valves around woodyard perimeter.
Boiler Area	Hose stations and portable extinguishers. Manual alarm stations.
Maintenance and Office Areas	Sprinkler system, portable extinguishers and manual alarm stations.
Turbine Area	Hose stations and portable extinguishers. Manual alarm stations, and sprinkler system around lube oil area.
Control Room	Portable extinguishers, smoke detectors and manual alarm stations.

The local water system is assumed to provide sufficient capacity and pressure for the fire protection system, therefore, fire pumps and onsite fire water storage will not be supplied.

23. Makeup and Condensate Water Treatment

a. System Function

The function of the water treatment system is to provide demineralized makeup water to the boiler system at the proper flow and quality.

b. System Description

The water treatment system will consist of two rented cation-anion demineralizer systems (or equivalent). Supply water to the demineralizer will be provided by the makeup water system.

Both demineralizers will be designed to produce or process the required quantities of boiler makeup water, and boiler blowdown at a quality within the recommended range of the boiler and turbine generator manufacturers.

A degasifier will not be provided.

A silica analyzer will be provided which can be used to monitor silica levels in the treated water after the mixed-bed bottles, or after the anion bottles. A high silica signal will also close the demineralizer inlet control valve and alarms in the control room, notifying the operator it is time to switch to the standby bottles.

24. Wastewater Treatment

a. System Function

The purpose of this system will be to gather, treat as required, and dispose of wastewater from the plant.

b. System Description

Boiler and turbine area drains will be directed to an oil separator unit.

Condensing system and boiler blowdown will be discharged to the sewer system.

Sanitary drains will be provided to dispose of sanitary wastewater. Discharge from the plant drains system goes through an oil separator before discharging to the sewer system.

Storm drainage will be accomplished by connecting to an existing base network, if applicable. This interconnection of drainage services would eliminate the need for onsite drainage basins.

25. Chemical Feed

a. System Function

The function of the chemical feed system will be to treat and supply the proper chemicals to the condensate system, and to eliminate problems in the boiler caused by scale, corrosion, carry over, and caustic embrittlement.

b. System Description

A boiler chemical injection package will maintain proper boiler cycle water chemistry. The system will be composed of three storage drums and positive displacement pumps that inject chemicals into the steam drum and deaerator.

Phosphate and morpholine will be injected into the drum and condenser hotwell to reduce boiler scale deposits and adjust pH, respectively.

Sulfite will be injected into the feedwater to neutralize residual oxygen, thus preventing oxygen corrosion.

Process sampling will provide a means for verifying the chemical composition of various process media.

Grab sample connections will be furnished for the testing of steam and water quality throughout the cycle. Sample connections will be provided at the main steam header, the boiler drum, the feedwater line near the economizer, the condensate pump discharge, and the cooling water system. The steam, feedwater, and boiler water sample points will be provided with sample coolers.

Samples will be taken manually and analyzed in laboratory facilities. Samples will be analyzed for impurities such as soluble gases, suspended solids, and dissolved solids. An excess level in any of these areas will be corrected by making proper adjustments in the water treatment system.